

ARTICLE I – GENERAL PROVISIONS

1. DEFINITIONS AND INTERPRETATION.

1.1 The general provisions of this Article I shall apply to this ISO Tariff.

1.2 Definitions.

Capitalized terms used in this ISO Tariff shall have the meanings set out in the Master Definitions Supplement set out in Appendix A to this ISO Tariff unless otherwise stated or the context otherwise requires.

1.3 Rules of Interpretation.

1.3.1 In this ISO Tariff “includes” or “including” shall mean “including without limitation”.

1.3.2 In this ISO Tariff, unless the context otherwise requires:

- (a) the singular shall include the plural and vice versa;
- (b) references to a Section or Appendix shall mean a section or appendix of this ISO Tariff;
- (c) references to any law shall be deemed references to such law as it may be amended, replaced or restated from time to time;
- (d) any reference to a “person” includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization or other entity, in each case, whether or not having separate legal personality;
- (e) any reference to a day, month, week or year is to a calendar day, month, week or year.
- (f) Unless the context otherwise requires, if the provisions of a Protocol and this ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency.
- (g) A reference in this ISO Tariff or 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.

- (h) Unless the context otherwise requires, if the provisions of a Protocol or this ISO Tariff and those of an existing contract conflict, with respect to Outage coordination, the existing contract will prevail to the extent of the inconsistency.
- (i) Time references are references to prevailing Pacific time.
- (j) The Operating Procedures referenced in this ISO Tariff, as may be amended from time to time, shall be posted on the ISO Home Page and such references in this ISO Tariff shall be to the Operating Procedures then posted on the ISO Home Page.
- (k) Any reference to a day or Trading Day, week, month or year is a reference to a calendar day, week, month or year except that a reference to a Business Day shall mean a day on which the banks in California are open for business.
- (l) Titles. The captions and headings in this ISO Tariff are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the rates, terms, and conditions of this ISO Tariff.

2. ACCESS TO THE ISO CONTROLLED GRID.

2.1 Open Access.

The ISO shall, subject to Sections 2.2 and 3, provide to all Eligible Customers open and non-discriminatory access to the ISO Controlled Grid regardless of the locations of their connections to the ISO Controlled Grid in accordance with the terms of this ISO Tariff including, in particular, the procedures for scheduling and Congestion Management. Energy and Ancillary Services may be transmitted on behalf of an Eligible Customer into, out of or through the ISO Controlled Grid only if scheduled by a Scheduling Coordinator. A Scheduling Coordinator must ensure that each Eligible Customer which it represents has all appropriate licenses or authorizations from the Local Regulatory Authority, FERC or any other regulatory body.

2.2 Eligibility of Customers for Direct Access or Wholesale Sales.

The eligibility of an End-Use Customer for Direct Access will be determined in accordance with the Direct Access eligibility and phase-in procedures (if any) adopted by the Local Regulatory Authority. Any dispute as to whether an End-Use Customer meets the eligibility criteria must be resolved by the Local Regulatory Authority prior to the ISO providing Direct Access to that End-Use Customer.

A Wholesale Customer shall not be entitled to participate in Wholesale Sales through a Scheduling Coordinator if it is not entitled to wholesale transmission service pursuant to the provisions of FPA Section 212(h).

3 FACILITIES FINANCED BY LOCAL FURNISHING BONDS OR OTHER TAX-EXEMPT BONDS.

3.1 This Section 3 applies only to transmission facilities which are under the Operational Control of the ISO and are owned by a Local Furnishing Participating TO or other Tax Exempt Participating TO. Nothing in this ISO Tariff or the TCA shall compel (and the ISO is not authorized to request) any Local Furnishing Participating TO or other Tax Exempt Participating TO to violate: (1) restrictions applicable to facilities which are part of a system that was financed in whole or part with Local Furnishing Bonds or other Tax Exempt Debt or (2) the contractual restrictions and covenants regarding the use of any transmission facilities specified in Appendix B to the TCA.

3.2 Each Local Furnishing Participating TO and other Tax Exempt Participating TO shall cooperate with and provide all necessary assistance to the ISO in developing an ISO Protocol to meet the objectives of Section 3.1 and shall keep the ISO fully informed of any changes necessary to that ISO Protocol from time to time.

3.3 The ISO shall implement the ISO Protocol referred to in Section 3.1 provided that the Local Furnishing TOs and other Tax Exempt Participating TOs shall bear sole responsibility for the development of that ISO Protocol including the interpretation of all relevant legislation and the tax and other financial consequences of its implementation.

4 ROLES AND RESPONSIBILITIES.

4.1 [Not Used]

4.2 Market Participant Responsibilities.

4.2.1 Comply with Operating Orders Issued.

With respect to this Section 4.2, all Market Participants, including Scheduling Coordinators, Utility Distribution Companies, Participating Transmission Owners, Participating Generators, Control Area Operators (to the extent the agreement between the Control Area Operator and the ISO so provides), and Metered Subsystem Operators within the ISO Control Area and all System Resources shall comply fully and promptly with the ISO's Dispatch Instructions and operating orders, unless such operation would impair public health or safety. A Market Participant is not required to comply with an ISO operating order if it is physically impossible for the Market Participant to perform in compliance with that operating order. Shedding Load for a System Emergency does not constitute impairment to public health or safety. The Market Participant shall immediately notify the ISO of its inability to perform in compliance with the operating order. The ISO will honor the terms of Existing Contracts, **provided that** in a System Emergency and circumstances in which the ISO considers that a System Emergency is imminent or threatened, **holders of** Existing Rights must follow ISO operating orders even if those operating orders **directly** conflict with the terms of Existing Contracts. For this purpose ISO operating orders to shed Load shall not be considered as an impairment to public health or safety. This section does not prohibit a Scheduling Coordinator from modifying its Schedule or re-purchasing Energy in the Hour-Ahead Market.

4.2.2 Implementation of Instructions.

All Market Participants shall respond to ISO instructions with no more delay than specified in the response times set out in the ISO Tariff and Protocols.

4.3 Relationship Between ISO and Participating Tos.

4.3.1 Nature of Relationship.

Each Participating TO shall enter into a Transmission Control Agreement with the ISO. In addition to converting Existing Rights in accordance with Section 16.2.1A, and except as provided in Section 4.3.1.3, New Participating TOs will be required to turn over Operational Control of all facilities and Entitlements that: (1) satisfy the FERC's functional criteria for determining transmission facilities that should be placed under ISO Operational Control; (2) satisfy the criteria adopted by the ISO Governing Board identifying transmission facilities for which the ISO should assume Operational Control; and (3) are the subject of mutual agreement between the ISO and the Participating TOs. The ISO shall notify Market Participants when an application has been received from a potential Participating TO and shall notify Market Participants that a New Participating TO has executed the Transmission Control Agreement and the date on which the ISO will have Operational Control of the transmission facilities.

4.3.1.1 In any year, a Participating TO applicant must declare its intent in writing to the ISO to become a New Participating TO by January 1 or July 1, and provide the ISO with an application within 15 days of such notice of intent. Applicable agreements will be negotiated and filed with the Federal Energy Regulatory Commission as soon as possible for the New Participating TO, such that the Agreements can be effective the following July 1 or January 1.

4.3.1.2 With respect to its submission of Schedules to the ISO, a New Participating TO shall become a Scheduling Coordinator or obtain the services of a Scheduling Coordinator that has been certified in accordance with Section 4.5.1.1, which Scheduling Coordinator shall not be the entity's Responsible Participating TO in accordance with the Responsible Participating Transmission Owner Agreement, unless mutually agreed, and shall operate in accordance with the ISO Tariff and applicable agreements.

The New Participating TO shall assume responsibility for paying all Scheduling Coordinators charges regardless of whether the New Participating TO elects to become a Scheduling Coordinator or obtains the services of a Scheduling Coordinator.

4.3.1.3 Western Path 15 shall be required to turn over to ISO Operational Control only its rights and interests in the Path 15 Upgrade and shall not be required to turn over to ISO Operational Control Central Valley Project transmission facilities, Pacific AC Intertie transmission facilities, California-Oregon Transmission Project facilities, or any other new transmission facilities or Entitlements not related to the Path 15 Upgrade. For purposes of the ISO Tariff, Western Path 15 shall be treated with respect to revenue recovery as a Project Sponsor in accordance with Section 24.7.

4.3.1.4 The capacity provided to the ISO under the Transmission Exchange Agreement originally accepted by FERC in Docket No. ER04-688 is deemed to be ISO Controlled Grid facilities and is subject to all terms and conditions of the ISO Tariff.

4.3.1.5 Each Participating TO must provide its Local Reliability Criteria to the ISO, as required by the TCA.

4.4 Relationship Between ISO And UDCs.

4.4.1 General Nature of Relationship Between ISO and UDCs.

4.4.1.1 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 UDC directly connected to the ISO Controlled Grid unless the relevant UDC has entered into a UDC Operating Agreement. The UDC Operating Agreement shall require UDCs to comply with the applicable provisions of this Section 4.4 and any other expressly applicable Sections of this ISO Tariff and the ISO Protocols as these may be amended from time to time.

4.4.1.2 The ISO shall operate the ISO Controlled Grid, and each UDC shall operate its Distribution System at all times in accordance with Good Utility Practice and in a manner which ensures safe and reliable operation. The ISO shall, in respect of its obligations set forth in this Section 4.4, have the right by agreement to delegate certain operational responsibilities to the relevant Participating TO or UDC pursuant to this Section 4.4. All information made available to UDCs by the ISO shall also be made available to Scheduling Coordinators. All information pertaining to the physical state or operation, maintenance and failure of the UDC Distribution System affecting the operation of the ISO Controlled Grid

that is made available to the ISO by the UDC shall also be made available to Scheduling Coordinators upon receipt of reasonable notice.

4.4.3 UDC Responsibilities.

Recognizing the ISO's duty to ensure efficient use and reliable operation of the ISO Controlled Grid consistent with the Applicable Reliability Criteria, each UDC shall:

4.4.3.1 operate and maintain its facilities, in accordance with applicable safety and reliability standards, regulatory requirements, applicable operating guidelines, applicable rates, tariffs, statutes and regulations governing their provision of service to their End-Use Customers and Good Utility Practice so as to avoid any material adverse impact on the ISO Controlled Grid;

4.4.3.2 provide the ISO Outage Coordination Office each year with a schedule of upcoming maintenance (including all equipment Outages) that has a reasonable potential of impacting the ISO Controlled Grid in accordance with Section 9.3.6 of this ISO Tariff and in accordance with the other scheduling procedures described in this ISO Tariff;

4.4.3.3 coordinate with the ISO, Participating TOs and Generators to ensure that ISO Controlled Grid Critical Protective Systems, including relay systems, are installed and maintained in order to function on a coordinated and complementary basis with UDCs, Generator's and Participating TO's protective systems.

4.4.3.4 Each UDC shall coordinate any requests for emergency Outages on point of interconnection equipment directly with the appropriate ISO Control Center as specified in Section 7.1.

4.4.6 System Emergency Reports: UDC Obligations.

4.4.6.1 Each UDC shall maintain all appropriate records pertaining to a System Emergency.

4.4.6.2 Each UDC shall cooperate with the ISO in the preparation of an Outage review pursuant to Section 7.4.13.

4.4.7 Coordination of Expansion or Modifications to UDC Facilities.

Each UDC and the Participating TO with which it is interconnected shall coordinate in the planning and implementation of any expansion or modifications of a UDC's or Participating TO's system that will affect their transmission interconnection, the ISO Controlled Grid or the transmission services to be required by the UDC. The Participating TO shall be responsible for coordinating with the ISO.

4.4.8 Information Sharing.

4.4.8.1 System Planning Studies.

The ISO, Participating TOs and UDCs shall share information such as projected Load growth and system expansions necessary to conduct necessary System Planning Studies to the extent that these may impact the operation of the ISO Controlled Grid.

4.4.8.2 System Surveys and Inspections.

The ISO and each UDC shall cooperate with each other in performing system surveys and inspections to the extent these relate to the operation of the ISO Controlled Grid.

4.4.8.3 Reports.

4.4.8.3.1 The ISO shall make available to the UDCs any public annual reviews or reports regarding performance standards, measurements and incentives relating to the ISO Controlled Grid and shall also make available, upon reasonable notice, any such reports that the ISO receives from the Participating TOs. Each UDC shall make available to the ISO any public annual reviews or reports regarding performance standards, measurements and incentives relating to the UDC's distribution system to the extent these relate to the operation of the ISO Controlled Grid.

4.4.8.3.2 The ISO and UDCs shall develop an operating procedure to record requests received for Maintenance Outages by the ISO and the completion of the requested maintenance and turnaround times.

4.4.8.3.3 The UDCs shall maintain records that substantiate all maintenance performed on UDC facilities which are under the Operational Control of the ISO. These records shall be made available to the ISO upon receipt of reasonable notice.

4.4.8.4 Installation of and Rights of Access to UDC Facilities.

4.4.8.4.1 Installation of Facilities.

4.4.8.4.1.1 Meeting Service Obligations. The ISO and the UDC shall each have the right on reasonable notice to install or to have installed equipment (including metering equipment) or other facilities on the property of the other, to the extent that such installation is necessary for the installing party to meet its service obligations unless to do so would have a negative impact on the reliability of the service provided by the party owning the property.

4.4.8.4.1.2 Governing Agreements for Installations. The ISO and the UDC shall enter into agreements governing the installation of equipment or other facilities containing customary, reasonable terms and conditions.

4.4.8.4.2 Access to Facilities.

The UDCs shall grant the ISO reasonable access to UDC facilities free of charge for purposes of inspection, repair, maintenance, or upgrading of facilities installed by the ISO on the UDC's system, provided that the ISO must provide reasonable advance notice of its intent to access UDC facilities and opportunity for UDC staff to be present. Such access shall not be provided unless the parties mutually agree to the date, time and purpose of each access. Agreement on the terms of the access shall not be unreasonably withheld.

4.4.8.4.3 Access During Emergencies.

Notwithstanding any provision in this Section 4.4 the ISO may have access, without giving prior notice, to any UDC's equipment or other facilities during times of a System Emergency or where access is needed in connection with an audit function.

4.4.8.5 Provision of Information for CRRs to Reflect Load Migration.

Each UDC shall provide to the CAISO information as provided in Section 36.8.5.2 of Appendix BB that enables the CAISO to perform transfers of CRRs that reflect Load Migration in a timely manner as required in Section 36.8.5 of Appendix BB.

4.4.9 UDC Facilities under ISO Control.

The ISO and each UDC shall enter into an agreement in relation to the operation and maintenance of the UDC's facilities which are under the ISO's Operational Control.

4.5 Responsibilities of a Scheduling Coordinator.

4.5.1 Scheduling Coordinator Certification.

Only Scheduling Coordinators that the CAISO has certified as having met the requirements of this Section 4.5.1 may participate in the CAISO's Energy and Ancillary Services markets. Scheduling Coordinators offering Ancillary Services shall additionally meet the requirements of Section 8.

Each Scheduling Coordinator shall:

- (a) demonstrate to the CAISO's reasonable satisfaction that it is capable of performing the functions of a Scheduling Coordinator under this CAISO Tariff including (without limitation) the functions specified in Sections 4.5.3 and 4.5.4;
- (b) identify each of the Eligible Customers (including itself if it trades for its own account) which it is authorized to represent as Scheduling Coordinator and confirm that the metering requirements under Section 10 are met in relation to each Eligible Customer that it represents under this CAISO Tariff;
- (c) confirm that each of the End-Use Customers it represents is eligible for Direct Access;
- (d) confirm that none of the Wholesale Customers it represents is ineligible for wholesale transmission service pursuant to the provisions of FPA Section 212(h);
- (e) demonstrate to the CAISO's reasonable satisfaction that it meets the financial criteria set out in Section 12;
- (f) enter into a Scheduling Coordinator Agreement with the CAISO; and
- (g) provide NERC tagging data.

4.5.1.1 Procedure to become a Scheduling Coordinator.

4.5.1.1.1 Scheduling Coordinator Application.

To become a Scheduling Coordinator, a Scheduling Coordinator Applicant must submit a completed application, as set forth in the applicable Business Practice Manual, to the CAISO by mail or in person. A Scheduling Coordinator Applicant may retrieve the application and necessary information from the CAISO Website.

4.5.1.1.2 CAISO Information.

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

- (a) the Scheduling Coordinator Application Form, as set forth in the applicable Business Practice Manual;
- (b) the CAISO Tariff and Business Practice Manuals; and
- (c) forms for a credit application for Scheduling Coordinator Applicants applying for Unsecured Credit Limits and for provision of Financial Security to be provided pursuant to Section 12.

4.5.1.1.3 Duplicate Information.

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

registered, the CAISO will return the application with an explanation that only one Scheduling Coordinator may register with the CAISO for the meter or Meter Point in question and that a Scheduling Coordinator has already registered or that more than one Scheduling Coordinator is attempting to register for that meter or Meter Point. The CAISO 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 120 days before the proposed commencement of service, the Scheduling Coordinator Applicant must return a completed application form with the non-refundable application fee of \$5,000 to cover the application processing costs.

4.5.1.1.5 Notice of Receipt.

Within three (3) Business Days of receiving the application, the CAISO will send electronic notification to the Scheduling Coordinator Applicant that it has received the application and the non-refundable fee.

4.5.1.1.6 CAISO Review of Application.

Within ten (10) Business Days after receiving an application, the CAISO will provide electronic notification to the Scheduling Coordinator Applicant whether the Scheduling Coordinator Applicant has submitted all necessary information as set forth in Section 4.5.1, and the Scheduling Coordinator Application Form set forth in the applicable Business Practice Manual.

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 120 days after the date the application, was filed, unless waived by the CAISO;
- (b) financial and credit information as set forth in Section 12; and
- (c) the prescribed non-refundable application fee of \$5,000.

4.5.1.1.6.2 Scheduling Coordinator Applicant's Obligation for Contracts.

A Scheduling Coordinator Applicant must certify that it is duly authorized to represent the Generators and Loads that are its Scheduling Coordinator Customers and must further certify that:

- (a) represented Generators have entered into Participating Generator Agreements or Qualifying Facility Participating Generator Agreements as provided in Appendices B.2 and B.3, respectively with the CAISO;
- (b) represented UDCs have entered into UDC Operating Agreements as provided in Appendix B.8 with the CAISO;
- (c) represented CAISO Metered Entities have entered into Meter Service Agreements for CAISO Metered Entities as provided in Appendix B.6 with the CAISO;
- (d) none of the Wholesale Customers it will represent are ineligible for wholesale transmission service pursuant to the provisions of the FPA Section 212(h); and
- (e) each End-Use Customer it will represent is eligible for Direct Access service pursuant to an established program approved by the California Public Utilities Commission or a Local Regulatory Authority.

4.5.1.1.7 Deficient Application.

In the event that the CAISO has determined that the application is deficient, the CAISO will send an electronic notification of the deficiency to the Scheduling Coordinator Applicant within ten (10) Business Days of receipt by the CAISO of the application explaining the deficiency and requesting additional information.

4.5.1.1.7.1 Scheduling Coordinator Applicant's Additional Information.

Once the CAISO requests additional information, the Scheduling Coordinator Applicant has five (5) Business Days, or such longer period as the CAISO may agree, to provide the additional material requested by the CAISO.

4.5.1.1.7.2 No Response from Scheduling Coordinator Applicant.

If the Scheduling Coordinator Applicant does not submit additional information within five (5) Business Days or the longer period referred to in Section 4.5.1.1.7.1, the application may be rejected by the CAISO.

4.5.1.1.8 CAISO Approval Or Rejection Of An Application.

4.5.1.1.8.1 Approval or Rejection Notification.

(a) If the CAISO approves the application, it will send an electronic notification of approval. In addition, the CAISO will provide a Scheduling Coordinator Agreement, a Meter Service Agreement for Scheduling Coordinators as provided in Appendix B.7, if applicable, any other applicable agreements, and any required CAISO network connectivity security agreement for the Scheduling Coordinator Applicant's signature.

(b) If the CAISO rejects the application, the CAISO will send an electronic notification of rejection stating one or more of the following grounds:

- i. incomplete information;
- ii. non-compliance with credit requirements pursuant to Section 12;
- iii. non-compliance with third party contractual obligations;
- iv. non-compliance with technical requirements; or
- v. non-compliance with any other CAISO Tariff requirements.

Upon request, the CAISO will provide guidance as to how the Scheduling Coordinator Applicant can cure the grounds for the rejection.

4.5.1.1.8.2 Time for Processing Application.

The CAISO will make a decision whether to accept or reject the application within ten (10) Business Days of receipt of the application. If more information is requested, the CAISO will make a final decision within ten (10) Business Days of the receipt of all outstanding or additional information requested.

4.5.1.1.9 Scheduling Coordinator Applicant's Response.

4.5.1.1.9.1 Scheduling Coordinator Applicant's Acceptance.

If the CAISO accepts the application, the Scheduling Coordinator Applicant must return an executed Scheduling Coordinator Agreement, Meter Service Agreement for Scheduling Coordinators, if applicable, any other applicable agreements, and a completed credit application and Financial Security provided pursuant to Section 12, 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 six (6) months after the CAISO's issuance of a rejection notification.

4.5.1.1.9.2.2 Appeal.

The Scheduling Coordinator Applicant may also appeal against the rejection of an application by the CAISO. An appeal must be submitted within twenty (20) Business Days following the CAISO's issuance of a notification of 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 CAISO will not certify that a Scheduling Coordinator Applicant has become a Scheduling Coordinator until the Scheduling Coordinator Applicant has completed all of the following requirements:

- (a) provided the technical/operational information required to complete the Scheduling Coordinator Application Form set forth in the applicable Business Practice Manual, and to comply with Section 10.3;
- (b) executed a network connectivity security agreement for access to the CAISO's software used in conducting business with the CAISO and compliance with the CAISO's system security requirements in a form approved by the CAISO, if applicable;
- (c) obtained and installed any required software for functional interface for Validation, Estimation and Editing meter values (VEE), if applicable;

- (d) undertaken required training and testing regarding the use of the CAISO's market, operating, and technical systems, as specified in the applicable Business Practice Manual;
- (e) provided its bank account information and arranged for Fed-Wire transfers;
- (f) provided an emergency plan specifying the procedures by which Scheduling Coordinator operations and contacts with the CAISO will be maintained during an emergency, containing information specified in the applicable Business Practice Manual; and
- (g) obtained and installed a computer link and any necessary software in order to communicate with the CAISO, as specified in the applicable Business Practice Manual.

Additional instructions for completing the foregoing requirements will be set forth in a Business Practice Manual posted on the CAISO Website.

4.5.1.1.10.2 Application Closure after 12 Months.

The CAISO will not certify a Scheduling Coordinator Applicant as a Scheduling Coordinator until the Scheduling Coordinator Applicant has completed all of the requirements for certification set forth in this Section 4.5 to the CAISO's satisfaction within twelve (12) months following the CAISO's acceptance of the application for processing. If the Scheduling Coordinator Applicant has not completed all the above referenced requirements within twelve (12) months after the CAISO's acceptance of the application, the CAISO may close the Scheduling Coordinator Applicant's application. The CAISO shall provide the Scheduling Coordinator Applicant thirty (30) days advance notice of its intent to close the application. If the CAISO closes the application, the Scheduling Coordinator Applicant must submit a new application and non-refundable application fee if it continues to request certification as a Scheduling Coordinator.

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 a Scheduling Coordinator Agreement, a Meter Service Agreement for Scheduling Coordinators, if applicable, and any other applicable agreements with the CAISO;
- (c) it has met the credit requirements of Section 12; and
- (d) it has fulfilled all technical/operational requirements of Sections 4.5.4.1 and 4.5.1.1.10.1.

The CAISO 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 CAISO's satisfaction, at least ten (10) Business 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 CAISO of any changes to any of the information submitted by it to the CAISO as part of the application process, including any changes to the additional information requested by the CAISO and including but not limited to changes in its credit ratings. The applicable Business Practice Manual sets forth the procedures for changing the Scheduling Coordinator's information and timing of notifying the CAISO of such changes.

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

The Scheduling Coordinator has an ongoing obligation to inform the CAISO within three (3) Business Days of any change to its credit ratings or any Material Change in Financial Condition.

4.5.1.2.2 CAISO'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 CAISO of a material change in its information provided to the CAISO, which may affect the reliability or safety of the CAISO Controlled Grid, or the financial security of the CAISO, the CAISO may suspend or terminate the Scheduling Coordinator's rights under the CAISO Tariff in accordance with the terms of Sections 12 and 4.5 respectively. If the CAISO intends to terminate the Scheduling Coordinator's rights it shall file a notice of termination with FERC, if required by FERC, in accordance with the terms of the Scheduling Coordinator Agreement. Such termination shall be effective upon acceptance by FERC of a notice of termination, if required by FERC rules, or as otherwise permitted by FERC rules.

4.5.1.3 Additional Scheduling Coordinator Identification Code Registration.

A Scheduling Coordinator Applicant is granted one Scheduling Coordinator Identification Code with its application fee. Requests may be made for additional Scheduling Coordinator Identification Codes. The fee for each additional Scheduling Coordinator Identification Code is \$500 per month, or as otherwise specified in Schedule 1 of Appendix F.

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 Monthly Forecasts. Submitting to the ISO its forecasted monthly and annual peak Demand in the ISO Control Area and/or its forecasted monthly and annual Generation capacity, as applicable. The forecasts shall be submitted to the ISO electronically on a monthly basis by noon of the 18th working day of the month and 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 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 Subject to Sections 4.5.4.2.1.2, each Scheduling Coordinator shall submit to the ISO a Day-Ahead Schedule (1) for each hour ending 7 through 22 of each Trading Day that includes at least ninety-five percent (95%) of that Scheduling Coordinator's Demand Forecast, pursuant to Section 31.1.4.1, for each hour, for each UDC or MSS Service Area, with respect to all entities for which the Scheduling Coordinator schedules in the applicable UDC or MSS Service Areas and (2) for each hour ending 1 through 6, 23 and 24 of each Trading Day that includes at least seventy-five percent (75%) of that Scheduling Coordinator's Demand Forecast for each hour, for each UDC or MSS Service Area, with respect to all entities for which the Scheduling Coordinator schedules in the applicable UDC or MSS Service Areas. For purposes of Section 4.5.4.2.1, the Day-Ahead Schedule shall be either a Revised Schedule pursuant to Section 30.3.4 if one is submitted by the Scheduling Coordinator, or, if the Scheduling Coordinator does not submit a revised Schedule, a Preferred Day-Ahead Schedule pursuant to Section 30.3.1.

The requirements of this section do not apply to (a) the portion of a Scheduling Coordinator's Demand associated with Station Power and (b) the Scheduling Coordinator's Demand within a UDC or MSS Service Area if the Scheduling Coordinator's maximum Demand within that UDC or MSS Service Area during the preceding twelve (12) months was less than one (1) megawatt, provided that this exemption shall not apply to any Scheduling Coordinator that did not submit Schedules for any metered Demand within a UDC or MSS Service Area over the preceding twelve (12) month period.

4.5.4.2.1.2 Exempt Scheduling Deviations by a Scheduling Coordinator in each UDC or MSS Service Area below the ninety-five percent (95%) and seventy-five percent (75%) scheduling levels specified in Section 4.5.4.2.1.1 shall not be deemed violations of Section 4.5.4.2.1.1.

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 Scheduling Coordinator Agreement and Suspension of Certification.

(a) A Scheduling Coordinator's Scheduling Coordinator Agreement may be terminated by the CAISO 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 five (5) Business Days after the CAISO has given written notice of the default;

- (ii) if the Scheduling Coordinator fails to pay any sum under this CAISO Tariff and fails to remedy the default within a period of five (5) Business Days after the CAISO has given written notice of the default;

(iii) if the Scheduling Coordinator commits any other default under this CAISO Tariff or any of the CAISO Business Practice Manuals which, if capable of being remedied, is not remedied within thirty (30) days after the CAISO has given it written notice of the default; or

(iv) if the Scheduling Coordinator does not schedule or bid in the CAISO's markets for Energy or Ancillary Services for a period of twelve (12) consecutive months and fails to comply with the provisions of Section 4.5.4.4.2 within 120 days after the CAISO has given it written notice of the CAISO's intent to terminate its Scheduling Coordinator Agreement.

(b) A Scheduling Coordinator's Scheduling Coordinator Agreement may be terminated by the Scheduling Coordinator on sixty (60) days written notice to the CAISO, provided that such notice shall not be effective to terminate the Scheduling Coordinator Agreement until the Scheduling Coordinator has complied with all applicable requirements of Section 4.5.2.

The CAISO shall, following termination of a Scheduling Coordinator Agreement and within thirty (30) days of being satisfied that no sums remain owing by the Scheduling Coordinator under the CAISO Tariff, return or release to the Scheduling Coordinator, as appropriate, any money or credit support provided by such Scheduling Coordinator to the CAISO under Section 12.

4.5.4.4.1 Pending the effective date of termination of service pursuant to Section 4.5.4.5.1, the CAISO will suspend the certification of a Scheduling Coordinator which has received a notice of termination under Section 4.5.4.4(a) and the Scheduling Coordinator will not be eligible to schedule or bid in the CAISO's Energy and Ancillary Services markets.

4.5.4.4.2 A Scheduling Coordinator that has received a notice of the CAISO's intent to terminate its Scheduling Coordinator Agreement for failure to schedule or bid in the CAISO's markets for Energy and Ancillary Services for a period of twelve (12) consecutive months pursuant to Section 4.5.4.4(a)(iv) will avoid having its Scheduling Coordinator Agreement terminated and will have its certification reinstated if it completes the testing and training required for Scheduling Coordinator certification as set forth in the applicable Business Practice Manual within 120 days after the CAISO's issuance of the notice of intent to terminate.

4.5.4.5 Notification of Termination.

The ISO shall, promptly after providing written notice of default to a Scheduling Coordinator as specified in Section 4.5.4.4 (a), notify the Scheduling Coordinators that could be required to represent End Use Eligible Customers of the Scheduling Coordinator under Section 4.5.4.6.2 if the default is not cured. The ISO shall, as soon as reasonably practicable following the occurrence of any of the events specified in Section 4.5.4.4, notify the Scheduling Coordinator and the Scheduling Coordinators that could be required to represent End Use Eligible Customers of the defaulting Scheduling Coordinator, and the UDCs, and shall as soon as reasonably practicable after the issuance of such notice of termination post such notice on the ISO Home Page. Termination of the Scheduling Coordinator Agreement will automatically remove the Scheduling Coordinator's certification under Section 4.5 and Section 8.4.

4.5.4.5.1 Filing of Notice of Termination.

Any notice of termination given pursuant to Section 4.5.4.4 shall also be filed by the CAISO with FERC, if required by FERC rules, if the non-compliance is not remedied within the period specified in Section 4.5.4.4, and it shall be effective in accordance with FERC rules.

4.5.4.6 Continuation of Service on Termination.

4.5.4.6.1 Option for Eligible Customers to choose a new Scheduling Coordinator.

When the ISO suspends the certification of a Scheduling Coordinator pending termination, Eligible Customers of the defaulting Scheduling Coordinator shall be entitled to select another Scheduling Coordinator to represent them. The ISO will post notice of any suspension on the ISO Home Page. Until the ISO is notified by another Scheduling Coordinator that it represents an Eligible Customer of the defaulting Scheduling Coordinator, the Eligible Customer of the defaulting Scheduling Coordinator will receive interim service in accordance with Section 4.5.4.6.2.

4.5.4.6.2 Interim Service.

The ISO shall maintain a list of Scheduling Coordinators willing to represent Eligible Customers of a defaulting Scheduling Coordinator, which list may be differentiated by UDC Service Area. Scheduling Coordinators who indicate to the ISO their desire to be on such list shall be placed thereon by the ISO in random order.

(a) When the ISO suspends the certification of a Scheduling Coordinator in accordance with Section 4.5.4.4.1, Eligible Customers of the defaulting Scheduling Coordinators shall be assigned to all Scheduling Coordinators on the list established pursuant to Section 4.5.4.6.2 in a non-discriminatory manner to be established by the ISO, and each Eligible Customer shall thereafter be represented by the Scheduling Coordinator to which it is assigned unless and until it selects another Scheduling Coordinator in accordance with Section 4.5.4.6.1, subject to subsection (b).

(b) Unless the ISO is notified by another Scheduling Coordinator that it represents an Eligible Customer of a defaulting Scheduling Coordinator within seven (7) days of the notice of termination being posted on the ISO Home Page, the Scheduling Coordinator to which that Eligible Customer has been assigned in accordance with subsection (a) may establish a reasonable minimum period for service, not to exceed thirty (30) days.

(c) In the event no Scheduling Coordinator indicates its willingness to represent Eligible Customers of a defaulting Scheduling Coordinator, the UDC, who has the obligation to serve End Use Customers of the Eligible Customer, if any, shall arrange to serve those End Use Customers of such Eligible Customers that are located within the Service Area of the UDC. Such service will be provided in a manner consistent with that which the UDC provides, pursuant to the rules and tariffs of the Local Regulatory Authority, for its bundled end-use customers.

(d) This Section shall not in any way require a UDC to provide or arrange for Scheduling Coordinator service for wholesale Eligible Customers.

4.6 Relationship Between ISO and Generators.

The ISO shall not Schedule Energy or Ancillary Services generated by any Generating Unit interconnected to the ISO Controlled Grid, or to the Distribution System of a Participating TO or of a UDC otherwise than through a Scheduling Coordinator. The ISO shall not be obligated to accept Schedules or Adjustment Bids or bids for Ancillary Services relating to Generation from any Generating Unit interconnected to the ISO Controlled Grid unless the relevant Generator undertakes in writing to the ISO to comply with all applicable provisions of this ISO Tariff as they may be amended from time to time, including, without limitation, the applicable provisions of this Section 4.6 and Section 7.4.

4.6.1 General Responsibilities.

4.6.1.1 Operate Pursuant to Relevant Provisions of ISO Tariff.

Participating Generators shall operate, or cause their facilities to be operated, in accordance with the relevant provisions of this ISO Tariff, including, but not limited to, the operating requirements for normal and emergency operating conditions specified in Section 7 and the requirements for the dispatch and testing of Ancillary Services specified in Section 8.

(i) Each Participating Generator shall immediately inform the ISO, through its respective Scheduling Coordinator, of any change or potential change in the current status of any Generating Units that are under the Dispatch control of the ISO. This will include, but not be limited to, any change in status of equipment that could affect the maximum output of a Generating Unit, the minimum load of a Generating

Unit, the ability of a Generating Unit to operate with automatic voltage regulation, operation of the PSSs (whether in or out of service), the availability of a Generating Unit governor, or a Generating Unit's ability to provide Ancillary Services as required. Each Participating Generator shall immediately report to the ISO, through its Scheduling Coordinator any actual or potential concerns or problems that it may have with respect to Generating Unit direct digital control equipment, Generating Unit voltage control equipment, or any other equipment that may impact the reliable operation of the ISO Controlled Grid.

(ii) In the event that a Participating Generator cannot meet its Generation schedule, whether due to a Generating Unit trip or the loss of a piece of equipment causing a reduction in capacity or output, the Participating Generator shall notify the ISO, through its Scheduling Coordinator at once. If a Participating Generator will not be able to meet a time commitment or requires the cancellation of a Generating Unit start up, it shall notify the ISO, through its Scheduling Coordinator at once.

4.6.1.2 Operate Pursuant to Relevant Operating Protocols.

Participating Generators shall operate, or cause their Generating Units and associated facilities to be operated, in accordance with the relevant operating protocols established by the ISO or, prior to the establishment of such protocols, the operating protocols established by the TO or UDC owning the facilities that interconnect with the Generating Unit of the Participating Generator.

4.6.3 Generators Connected to UDC Systems.

With regard to any Generating Unit directly connected to a UDC system, a Participating Generator shall comply with applicable UDC tariffs, interconnection requirements and generation agreements. With regard to a Participating Generator's Generating Units directly connected to a UDC system, the ISO and the UDC will coordinate to develop procedures to avoid conflicting ISO and UDC operational directives.

4.6.3.1 Exemption for Generating Units Less Than 1 MW.

A Generator with a Generating Unit directly connected to a UDC system will be exempt from compliance with this Section 4.6 and Section 10.1.3 in relation to that Generating Unit provided that (i) the rated

capacity of the Generating Unit is less than 1 MW, and (ii) the Generator does not use the Generating Unit to participate in the ISO's Ancillary Services and/or to submit Supplemental Energy bids. This exemption in no way affects the calculation of or any obligation to pay the appropriate charges or to comply with all the other applicable Sections of this ISO Tariff.

4.6.3.2 Existing Contracts for Regulatory Must-Take Generation.

Notwithstanding any other provision of this ISO Tariff, the ISO shall discharge its responsibilities in a manner which honors any contractual rights and obligations of the parties to contracts, or final regulatory treatment, relating to Regulatory Must-Take Generation of which protocols or other instructions are notified in writing to the ISO from time to time and on reasonable notice.

4.6.4 Identification of Generating Units.

Each Generator shall provide data identifying each of its Generating Units and such information regarding the capacity and the operating characteristics of the Generating Unit as may be reasonably requested from time to time by the ISO.

4.6.5 WECC Requirements.

4.6.5.1 Generator Performance Standard.

Participating Generators shall, in relation to each of their Generating Units, meet all applicable WECC standards including any standards regarding governor response capabilities, use of power system stabilizers, voltage control capabilities and hourly Energy delivery. Unless otherwise agreed by the ISO, a Generating Unit must be capable of operating at capacity registered in the ISO Controlled Grid interconnection data, and shall follow the voltage schedules issued by the ISO from time to time.

4.6.5.2 Reliability Criteria.

Participating Generators shall comply with the requirements of the WSCC Reliability Criteria Agreement, including the applicable WSCC Reliability Criteria set forth in Section IV of Annex A thereof. In the event that a Participating Generator fails to comply, it will be subject to the sanctions applicable to such failure. Such sanctions shall be assessed pursuant to the procedures contained in the WSCC Reliability Criteria

Agreement. Each and all of the provisions of the WSCC Reliability Criteria Agreement are hereby incorporated by reference into this Section 4.6.5.2 as though set forth fully herein, and Participating Generators shall for all purposes be considered Participants as defined in that Agreement, and shall be subject to all of the obligations of Participants, under and in connection with the WSCC Reliability Criteria Agreement. The Participating Generators shall copy the ISO on all reports supplied to the WECC in accordance with Section IV of Annex A of the WSCC Reliability Criteria Agreement.

4.6.5.3 Payment of Sanctions.

Each Participating Generator shall be responsible for payment directly to the WECC of any monetary sanction assessed against that Participating Generator by the WECC pursuant to the WSCC Reliability Criteria Agreement. Any such payment shall be made pursuant to the procedures specified in the WSCC Reliability Criteria Agreement.

4.6.6.2 Forced Outages.

Procedures equivalent to those set out in Section 9.3 shall apply to all Participating Generators in relation to Forced Outages.

4.6.7 Recordkeeping; Information Sharing.

4.6.7.1 Requirements for Maintaining Records.

Participating Generators shall provide to the ISO such information and maintain such records as are reasonably required by the ISO to plan the efficient use and maintain the reliability of the ISO Controlled Grid.

4.6.7.2 Providing Information to Generators.

The ISO shall provide to any Participating Generator, upon its request, copies of any operational assessments, studies or reports prepared by or for the ISO (unless such assessments studies or reports are subject to confidentiality rights or any rule of law that prohibits disclosure) concerning the operations of such Participating Generator's Generating Units, including, but not limited to, reports on major Generation Outages, available transmission capacity, and Congestion.

4.6.7.3 Preparation of Reports on Major Incidents.

In preparing any report on a major incident the ISO shall have due regard to the views of any Participating Generator involved or materially affected by such incident.

4.6.8 Sharing Information on Reliability of ISO Controlled Grid.

The ISO and each Participating Generator shall have the obligation to inform each other, as promptly as possible, of any circumstance of which it becomes aware (including, but not limited to, abnormal temperatures, storms, floods, earthquakes, and equipment depletions and malfunctions and deviations from the Registered Data and operating characteristics) that is reasonably likely to threaten the reliability of the ISO Controlled Grid or the integrity of the Participating Generator's facilities. The ISO and each Participating Generator shall also inform the other as promptly as possible of any incident of which it becomes aware (including, but not limited to, equipment outages, over-loads or alarms) which, in the case of a Participating Generator, is reasonably likely to threaten the reliability of the ISO Controlled Grid or, in the case of the ISO, is reasonably likely to adversely affect the Participating Generator's facilities. Such information shall be provided in a form and content which is reasonable in all the circumstances and sufficient to provide timely warning to the other party of the potential impact.

4.6.9 Access Right.

A participating Generator shall, at the request of the ISO and upon reasonable notice, provide access to its facilities and records (including those relating to communications, telemetry and direct control requirements) as necessary to permit the ISO or an ISO approved meter inspector to perform such testing as is necessary (i) to test the accuracy of any meters upon which the Participating Generator's compensation is based, or performance is measured, (ii) to test the Participating Generator's compliance with any performance standards pursuant to Section 4.6.5 of this ISO Tariff, (iii) to obtain information relative to a Forced Outage, or (iv) for Participating Intermittent Resources, to ensure compliance with provisions relating to the Participating Intermittent Resource Export Fee.

4.7 Relationship Between ISO and Participating Loads.

The ISO shall only accept bids for Supplemental Energy or Ancillary Services, or Schedules for self-provision of Ancillary Services, from Loads if such Loads are Participating Loads which meet standards

adopted by the ISO and published on the ISO Home Page. The ISO shall not schedule Energy or Ancillary Services from a Participating Load other than through a Scheduling Coordinator.

4.8 Relationship Between ISO and Eligible Intermittent Resources and Between the ISO and Participating Intermittent Resources.

The ISO shall not schedule Energy from an Eligible Intermittent Resource other than through a Scheduling Coordinator. No Adjustment Bids or Supplemental Energy bids may be submitted on behalf of Participating Intermittent Resources. Any Eligible Intermittent Resource that is not a Participating Intermittent Resource, or any Participating Intermittent Resource for which Adjustment Bids or Supplemental Energy bids are submitted shall be scheduled and settled as a Generating Unit for the associated Settlement Periods (except that the Forecasting Fee shall apply in such Settlement Periods).

4.8A Compliance with Scheduling and Data Provision Requirements. Pursuant to its obligation to notify FERC of any potential violations of Section 37.7 of this ISO Tariff, the ISO will routinely report any underscheduling behavior that it observes to FERC, for investigation as a potential violation of Section 37.7 of this ISO Tariff and/or FERC's Market Behavior Rule 2.

4.9 Metered Subsystems

4.9.1 General Nature of Relationship Between ISO and MSS.

4.9.1.1 An entity that is determined by the ISO to qualify as a Metered Subsystem and that undertakes in writing to the ISO to comply with all applicable provisions of the ISO Tariff as specified in that written agreement as they may be amended from time to time, including, without limitation, the applicable provisions of this Section 4.9, shall be considered an MSS Operator and shall have the rights and obligations set forth in this Section 4.9. The ISO shall not be obligated to accept Schedules, Adjustment Bids or bids for Ancillary Services which would require Energy to be transmitted to or from a Metered Subsystem unless the written undertaking of the MSS Operator of the Metered Subsystem has become effective.

4.9.2 Coordination of Operations. Each MSS Operator shall operate its MSS at all times in accordance with Good Utility Practice and Applicable Reliability Criteria, including WECC and NERC

criteria, and in a manner which ensures safe and reliable operation. All information pertaining to the physical state or operation, maintenance and failure of the MSS affecting the operation of the ISO Control Area that is made available to the ISO by the MSS Operator shall also be made available to Scheduling Coordinators, provided that the ISO shall provide reasonable notice to the MSS Operator. The ISO shall not be required to make information available to the MSS Operator other than information that is made available to Scheduling Coordinators.

4.9.3 Coordinating Maintenance Outages of MSS Facilities. Each MSS Operator shall make appropriate arrangements to coordinate Outages of Generating Units in accordance with Section 4.6. Each MSS Operator shall make appropriate arrangements to coordinate Outages of transmission facilities forming part of its MSS that will have an effect, or are reasonably likely to have an effect, on any interconnection between the MSS and the system of a Participating TO, prior to the submission by that Participating TO of its Maintenance Outage requirements under Section 9.3. The ISO will coordinate Outages of other Participating TOs transmission facilities that may affect the MSS.

4.9.4 MSS Operator Responsibilities.

The MSS Operator's written undertaking to the ISO shall obligate the MSS Operator to comply with all provisions of the ISO Tariff, as amended from time to time, applicable to the UDCs, including, without limitation, the applicable provisions of Section 4.4 and Section 7.4. In addition, recognizing the ISO's responsibility to promote the efficient use and reliable operation of the ISO Controlled Grid and the Control Area consistent with the Applicable Reliability Criteria, each MSS Operator shall:

4.9.4.1 operate and maintain its facilities, in accordance with applicable safety and reliability standards, regulatory requirements, applicable operating guidelines, applicable rates, tariffs, statutes and regulations governing their provision of service to their End-Use Customers and Good Utility Practice so as to avoid any material adverse impact on the ISO Controlled Grid, it being understood that, if the MSS Operator does not so operate and maintain its facilities and the ISO concludes, after notice is provided to the MSS Operator, that such failure impairs or threatens to impair the reliability of the ISO Controlled Grid,

the ISO may suspend MSS status, in accordance with this Section 4.9, until the MSS Operator demonstrates the ability and willingness to so operate and maintain its facilities;

4.9.4.2 provide the ISO Outage Coordination Office each year with a schedule of upcoming maintenance of facilities forming part of the MSS that will affect or is reasonably likely to affect the ISO Controlled Grid in accordance with Section 9.3.6;

4.9.4.3 coordinate with the ISO, Participating TOs and Generators to ensure that ISO Controlled Grid Critical Protective Systems, including relay systems, are installed and maintained in order to function on a coordinated and complementary basis with the protective systems of the MSS, Participating TOs and Generators and notify the ISO as soon as is reasonably possible of any condition of which it becomes aware that may compromise the ISO Controlled Grid Protective Systems;

4.9.4.4 be responsible for any Reliability Must-Run Generation and Voltage Support required for reliability of the MSS, including the responsibility for any costs of such Reliability Must-Run Generation, and Voltage Support and may satisfy this requirement through Generating Units owned by the MSS or under contract to the MSS;

4.9.4.5 be responsible for Black Start requirements for reliability of the MSS, however, if the MSS can self-provide this requirement, the MSS shall not pay its pro rata share of the Black Start requirement in accordance with Section 8.12.5; and

4.9.4.6 be responsible for Intra-Zonal Congestion Management and transmission line Outages within or at the boundary of the MSS, and all associated costs and not responsible for Intra-Zonal Congestion Management elsewhere in the Zone except to the extent that a Scheduling Coordinator is delivering Energy to or from the MSS.

4.9.5 Scheduling by or on behalf of a MSS Operator. All Schedules submitted on behalf of an MSS Operator for the delivery of Energy and Ancillary Services to Loads connected to the MSS and for the delivery of Energy and Ancillary Services from Generating Units forming part of the MSS or System Units shall be submitted by a Scheduling Coordinator that complies with all applicable provisions of the ISO Tariff, which Scheduling Coordinator may be the MSS Operator, provided that the MSS

Operator complies with all applicable requirements for Scheduling Coordinators. A Scheduling Coordinator shall separately identify Schedules that it submits on behalf of an MSS Operator.

4.9.5.1 Without limiting the foregoing, the Scheduling Coordinator for the MSS must submit gross generation information for the System Unit, Generating Unit, and information regarding imports, exports and Gross Loads to the ISO in the format and in accordance with the timelines applicable to other Scheduling Coordinators.

4.9.5.2 The Scheduling Coordinator for the MSS will designate, in discrete quantities and with prices for both Ancillary Services and Energy: (1) Schedules in Day-Ahead and Hour-Ahead Energy markets (including Schedules for internal Generation and internal Demand within the MSS), (2) bids or self-provided Schedules for Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve capacity and associated bid Energy, (3) Adjustment Bids, (4) Supplemental Energy bids, or (5) any feasible combination thereof.

4.9.6 System Emergencies.

4.9.6.1 The ISO has authority to suspend MSS control and direct, via communications with the MSS Operator, the operation of Generating Units within the MSS, including Generating Units that may comprise a System Unit, if such control is necessary to maintain ISO Controlled Grid reliability.

4.9.6.2 If a Load curtailment is required to manage System Emergencies, the ISO will determine the amount and location of Load to be reduced pursuant to Section 7.4.6 and 7.4.6.1. Each MSS Operator shall be responsible for notifying its customers and Generators connected to its system of curtailments and service interruption.

4.9.6.3 System Emergency Reports: MSS Obligations.

4.9.6.3.1 Each MSS Operator shall maintain all appropriate records pertaining to a System Emergency.

4.9.6.3.2 Each MSS Operator shall cooperate with the ISO in the preparation of an Outage review pursuant to Section 7.4.13.

4.9.7 Coordination of Expansion or Modifications to MSS Facilities.

Each MSS Operator and any Participating TO with which its system is interconnected, if applicable, shall coordinate in the planning and implementation of any expansion or modifications of a MSS's or Participating TO's system that will affect their transmission interconnection, the ISO Controlled Grid or the transmission services to be required by the MSS Operator. The MSS Operator and any Participating TO with which the MSS is interconnected shall be responsible for coordinating with the ISO.

4.9.8 Ancillary Service Obligations for MSS.

4.9.8.1 Ancillary Service obligations will be allocated to the Scheduling Coordinator scheduling Load within a MSS in accordance with the ISO Tariff. The ISO shall have the right to call upon Ancillary Service capacity self-provided by a Scheduling Coordinator for an MSS or procured by the ISO from such Scheduling Coordinator in accordance with the ISO Tariff. The Scheduling Coordinator representing the MSS Operator may bid or self-provide Ancillary Services from a System Unit or from individual Generating Units or Participating Loads in the MSS. Alternatively, the Scheduling Coordinator representing the MSS may purchase Ancillary Services from the ISO or third parties to meet all or part of its Ancillary Service obligations in accordance with the ISO Tariff.

4.9.8.2 If the MSS Operator desires to follow internal Load with a System Unit or Generating Units in the MSS, and also to provide Regulation to the ISO, the MSS must provide adequate telemetry consistent with the ISO Tariff and all applicable standards to allow performance in response to ISO AGC signals to be measured at the interconnection of the MSS to the ISO Controlled Grid.

4.9.9 Load Following.

4.9.9.1 The MSS Operator may operate a System Unit or Generating Units in the MSS to follow its Load, provided that: (a) the Scheduling Coordinator for the MSS Operator shall remain responsible for purchases of Imbalance Energy in accordance with the ISO Tariff if the MSS Operator does not operate its System Unit or Generating Units and schedule imports into the MSS, to match the metered Demand in the MSS and exports from the MSS; and (b) if the deviation between the Generation in the MSS and imports into the MSS and metered Demand in the MSS and exports from the MSS exceeds a deviation

band equal to three percent (3%) of the lesser of the MSS Operator's metered or Hour-Ahead scheduled Demand and exports from the MSS, adjusted for Forced Outages and any ISO directed firm Load Shedding for the MSS's portfolio as a whole (the "Deviation Band"), then the Scheduling Coordinator for the MSS Operator shall pay the additional amounts specified in Section 4.9.9.2. The Scheduling Coordinator for an MSS Operator that chooses to follow its Load in accordance with this Section 4.9.9 shall provide sixty (60) days advance notice to the ISO. If the Scheduling Coordinator later desires not to follow the Load of the MSS Operator, the Scheduling Coordinator shall provide sixty (60) days advance notice to the ISO that it will no longer follow Load.

4.9.9.2 Under the circumstances described in Section 4.9.9.1, the Scheduling Coordinator for an MSS Operator shall pay amounts based on a price that is the effective weighted average Ex Post Price applicable to the MSS's Scheduling Coordinator for the billing interval (the "Deviation Price"). The revenue received from these payments will be used as an off-set to the ISO's Grid Management Charge. The payments due from a Scheduling Coordinator will be calculated as follows:

4.9.9.2.1 If the metered Generation resources and imports into the MSS exceed the metered Demand and exports from the MSS, and Energy expected to be delivered by the Scheduling Coordinator for the MSS in response to the ISO's Dispatch instructions and/or Regulation set-point signals issued by the ISO's AGC by more than the Deviation Band, then the Scheduling Coordinator for the MSS Operator will pay the ISO an amount equal to one hundred percent (100%) of the product of the Deviation Price and the amount of the Imbalance Energy that is supplied in excess of the Deviation Band.

4.9.9.2.2 If metered Generation resources and imports into the MSS are insufficient to meet the metered Demand and exports from the MSS, and Energy expected to be delivered by the Scheduling Coordinator for the MSS in response to the ISO's Dispatch instructions and/or Regulation set-point signals issued by the ISO's AGC by more than the Deviation Band, then the Scheduling Coordinator for the MSS Operator shall pay the ISO an amount equal to the product of the Deviation Price and two hundred percent (200%) of the shortfall that is outside of the Deviation Band, in addition to the Imbalance Energy charges that may be applicable under the ISO Tariff.

4.9.9.3 If the ISO is charging Grid Management Charges for uninstructed deviations, and the Scheduling Coordinator for the MSS has uninstructed deviations associated with Load following from the MSS's resources, then the ISO will net the Generation and imports into the MSS to match the Demand and exports out of the MSS, and will not assess GMC associated with uninstructed deviations for such portion of Energy that is used to match MSS Demand and net exports.

4.9.9.3.1 If Generation, above the amount to cover Demand and exports, was sold into the ISO's Imbalance Energy market, then the Scheduling Coordinator for the MSS will be charged GMC associated with uninstructed deviations for this quantity.

4.9.9.3.2 If insufficient Generation and imports was available to cover Demand and exports, and the Scheduling Coordinator for the MSS purchased Imbalance Energy from the ISO's market, then such Scheduling Coordinator will be charged GMC associated with uninstructed deviations for this quantity.

4.9.9.3.3 Only GMC associated with uninstructed deviations (the Ancillary Services and Real-Time Energy Operations Charge (ASREO)) will be treated on a net basis. GMC for Control Area Services (CAS) will be charged based on Gross Load and exports out of the MSS. The Scheduling Coordinator for the MSS Operator will be assessed the GMC Congestion Management Charge (CONG) in accordance with Section 11.2.2.3. Ancillary Service bids accepted by the ISO and Instructed Energy will be assessed the GMC ASREO.

4.9.10 Information Sharing.

4.9.10.1 System Planning Studies and Forecasts.

The ISO, the MSS Operator and Participating TOs shall share information such as projected Load growth and system expansions necessary to conduct necessary system planning studies to the extent that these may impact the operation of the ISO Control Area. Each MSS Operator shall provide to the ISO annually its ten-year forecasts of Demand growth, internal Generation, and expansion of or replacement for any transmission facilities that are part of the MSS that will or may significantly affect any point of interconnection between the MSS and the ISO Controlled Grid. Such forecasts shall be provided on the date that UDCs are required to submit forecasts to the ISO under Section 4.4.8.1.

Each MSS Operator or each Scheduling Coordinator for an MSS Operator shall also submit weekly and monthly peak Demand Forecasts in accordance with the ISO's protocols.

4.9.10.2 System Surveys and Inspections.

The ISO and each MSS Operator shall cooperate with each other in performing system surveys and inspections to the extent these relate to the operation of the ISO Control Area.

4.9.10.3 Reports.

4.9.10.3.1 The ISO shall make available to each MSS Operator any public annual reviews or reports regarding performance standards, measurements and incentives relating to the ISO Controlled Grid and shall also make available, upon reasonable notice, any such reports that the ISO receives from Participating TOs. Each MSS Operator shall make available to the ISO any public annual reviews or reports regarding performance standards, measurements and incentives relating to the MSS's Distribution System to the extent these relate to the operation of the ISO Controlled Grid.

4.9.10.3.2 The ISO and the MSS Operators shall develop an operating procedure to record requests received for Maintenance Outages by the ISO and the completion of the requested maintenance and turnaround times.

4.9.10.3.3 Each MSS Operator shall promptly provide such information as the ISO may reasonably request concerning the MSS Operator's operation of the MSS to enable the ISO to meet its responsibility under the ISO Tariff to conduct reviews and prepare reports following major Outages. Where appropriate, the ISO will provide appropriate assurances that the confidentiality of commercially sensitive information shall be protected. The ISO shall have no responsibility to prepare reports on Outages that affect customers on the MSS, unless the Outage also affects customers connected to the system of another entity within the ISO Control Area. The MSS Operator shall be solely responsible for the preparation of any reports required by any governmental entity or the WECC with respect to any Outage that affects solely customers on the MSS.

4.9.10.3.4 Reliability Information. Each MSS Operator shall inform the ISO, and the ISO shall inform each MSS Operator, in each case as promptly as possible, of any circumstance of which it

becomes aware (including, but not limited to, abnormal temperatures, storms, floods, earthquakes, and equipment depletions and malfunctions and deviations from Registered Data and operating characteristics) that is reasonably likely to threaten the reliability of the ISO Controlled Grid or the integrity of the MSS respectively. Each MSS Operator and the ISO each shall also inform the other as promptly as possible of any incident of which it becomes aware (including, but not limited to, equipment outages, over-loads or alarms) which, in the case of the MSS Operator, is reasonably likely to threaten the reliability of the ISO Controlled Grid, or, in the case of the ISO, is reasonably likely to adversely affect the MSS. Such information shall be provided in a form and content which is reasonable in all the circumstances, sufficient to provide timely warning to the entity receiving the information of the threat and, in the case of the ISO, not unduly discriminatory with respect to the ISO's provision of similar information to other entities.

4.9.10.3.5 Forms. The ISO shall, in consultation with MSS Operators, jointly develop and, as necessary, revise, any necessary forms and procedures for collection, study, treatment, and transmittal of system data, information, reports and forecasts.

4.9.10.4 Each MSS Operator shall provide to the CAISO information as provided in Section 36.8.5.2 of Appendix BB that enables the CAISO to perform transfers of CRRs to reflect Load Migration in a timely manner as required in Section 36.8.5 of Appendix BB.

4.9.14 Installation of and Rights of Access to MSS Facilities.

4.9.14.1 Installation of Facilities.

4.9.14.1.1 Meeting Service Obligations.

The ISO and each MSS Operator shall each have the right, if mutually agreed, on reasonable notice to install or to have installed equipment (including metering equipment) or other facilities on the property of the other, to the extent that such installation is necessary for the installing party to meet its service obligations unless to do so would have a negative impact on the reliability of the service provided by the party owning the property.

4.9.14.1.2 Governing Agreements for Installations.

The ISO and the MSS Operator shall enter into agreements governing the installation of equipment or other facilities containing customary and reasonable terms and conditions.

4.9.14.2 Access to Facilities.

Each MSS Operator shall grant the ISO reasonable access to MSS facilities free of charge for purposes of inspection, repair, maintenance, or upgrading of facilities installed by the ISO on the MSS's system, provided that the ISO must provide reasonable advance notice of its intent to access MSS facilities. Such access shall not be provided unless the parties mutually agree to the date, time and purpose of each access. Agreement on the terms of the access shall not be unreasonably withheld.

4.9.14.3 Access During Emergencies.

Notwithstanding any provision in this Section 4.9, the ISO may have access, without giving prior notice, to any MSS Operator's equipment or other facilities during times of a System Emergency or where access is needed in connection with an audit function.

4.9.15 MSS System Unit.

4.9.15.1 A MSS Operator may aggregate one or more Generating Units and/or Participating Loads as a System Unit. Except as specifically provided in the agreement referred to in Section 4.9.1.1, all provisions of the ISO Tariff applicable to Participating Generators and to Generating Units (and, if the System Unit includes a Load, to Participating Loads), shall apply fully to the System Unit and the Generating Units and/or Loads included in it. The MSS Operator's written undertaking to the ISO in accordance with Section 4.9.1.1 shall obligate the MSS Operator to comply with all provisions of the ISO Tariff, as amended from time to time, applicable to the System Unit, including, without limitation, the applicable provisions of Section 4.6.1 and Section 7.4. In accordance with Section 7.3.1, the ISO will obtain control over the System Unit, not the individual Generating Unit, except for Regulation, to comply with Section 4.6.

4.9.15.2 Without limiting the generality of Section 4.9.15.1, a MSS Operator that owns or has an entitlement to a System Unit:

4.9.15.2.1 is required to have a direct communication link to the ISO's EMS satisfying the requirements applicable to Generating Units owned by Participating Generators, or Participating Loads, as applicable, for the System Unit and the individual resources that make up the System Unit;

4.9.15.2.2 shall provide resource-specific information regarding the Generating Units and Loads comprising the System Unit to the ISO through telemetry to the ISO's EMS;

4.9.15.2.3 shall obtain ISO certification of the System Unit's Ancillary Service capabilities in accordance with Section 8.4 and 8.10 before the Scheduling Coordinator representing the MSS may self-provide its Ancillary Service obligations or bid into the ISO's markets from that System Unit;

4.9.15.2.4 shall provide the ISO with control over the AGC of the System Unit, if the System Unit is supplying Regulation to the ISO or is designated to self-provide Regulation; and

4.9.15.2.5 shall install ISO certified meters on each individual resource or facility that is aggregated to a System Unit.

4.9.15.3 Subject to Section 4.9.15.5, the ISO shall have the authority to exercise control over the System Unit to the same extent that it may exercise control pursuant to the ISO Tariff over any other Participating Generator, Generating Unit or, if applicable, Participating Load, but the ISO shall not have the authority to direct the MSS Operator to adjust the operation of the individual resources that make up the System Unit to comply with directives issued with respect to the System Unit.

4.9.15.5 When and to the extent that Energy from a System Unit is scheduled to provide for the needs of Loads within the MSS and is not being bid to the ISO's Ancillary Service or Supplemental Energy markets, the ISO shall have the authority to dispatch the System Unit only to avert or respond to a circumstance described in the third sentence of Section 7.3.1 or, pursuant to Section 7.4.2.3, to a System Emergency.

4.9.16 MSS Settlements.

4.9.16.1 The ISO will assess the Scheduling Coordinator for the MSS the neutrality adjustments and Existing Contracts cash neutrality charges pursuant to Section 11.2.9 (or collect refunds therefore) based on the net metered Demand and exports of the MSS.

4.9.16.2 If the ISO is charging Scheduling Coordinators for summer reliability or demand programs, the MSS Operator may petition the ISO for an exemption of these charges. If the MSS

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

which ensures safe and reliable operation. The ISO shall, in respect of its obligations set forth in this Section 5, have the right by mutual agreement to delegate certain operational responsibilities to the relevant Participating TO or SUDC pursuant to this Section 5. All information made available to SUDCs by the ISO shall also be made available to Scheduling Coordinators. Any information, pertaining to the physical state, operation, maintenance or failure of the SUDC Distribution System that may cause a material adverse affect to the operation of the ISO Controlled Grid, that is made available to the ISO by the SUDC shall also be made available to Scheduling Coordinators upon receipt of reasonable notice.

5.2 Coordinating Maintenance Outages of SUDC Facilities.

Each SUDC and the Participating TO with which it is interconnected shall coordinate their Outage requirements with respect to their transmission interconnection facilities prior to the submission by that Participating TO of its maintenance Outage requirements under Section 9.3.

5.3 SUDC Responsibilities.

Recognizing the ISO's duty to ensure efficient use and reliable operation of the ISO Control Area and the ISO Controlled Grid consistent with the Applicable Reliability Criteria, each SUDC shall:

5.3.1 operate and maintain its Distribution System in accordance with applicable reliability standards, statutes and regulations, and Good Utility Practice so as to avoid any material adverse impact on the reliability of the ISO Control Area and the ISO Controlled Grid;

5.3.2 provide the ISO Outage Coordination Office each year with a schedule of upcoming maintenance on its transmission interconnection facilities with the ISO Controlled Grid that has a reasonable potential of causing a material adverse impact to the reliability of the ISO Controlled Grid.

5.4 System Emergencies.

5.4.1 In the event of a System Emergency, SUDCs shall comply with all directions from the ISO concerning the management and alleviation of the System Emergency and shall comply with all procedures concerning SUDCs for System Emergencies set out in the individual SUDC Operating Agreements.

5.4.2 During a System Emergency, the ISO and SUDCs shall communicate in accordance with procedures established in individual SUDC operating agreements.

5.5 Load Reduction.

5.5.1 If the ISO declares a Stage 1 System Emergency, the SUDC shall use any reasonably available local communication infrastructure to request that its customers curtail their electricity usage. The SUDC shall not be called separately in Stage 3 System Emergencies to manually shed Load. Load restoration of any voluntary Load reduction will occur once the ISO declares that a System Emergency no longer exists.

5.5.2 If the Participating TO sheds the SUDC Load associated with the Participating TO's transmission facilities, the Participating TO will provide timely information and work with the SUDC regarding SUDC Load restoration.

5.6 System Emergency Reports: SUDC Obligations.

5.6.1 Each SUDC shall maintain all appropriate records pertaining to a System Emergency in accordance with the SUDC's then-existing record retention practice or policy, provided the records are kept for a minimum of six (6) years.

5.6.2 In accordance with its SUDC Operating Agreement, each SUDC shall provide available information to the ISO regarding the ISO's preparation of an Outage review.

5.7 Coordination of Expansion or Modifications to SUDC Facilities.

Each SUDC and the Participating TO with which it is interconnected shall coordinate in the planning and implementation of any expansion or modifications of a SUDC's or Participating TO's system that will materially affect the reliability of their transmission interconnection facilities, the ISO Controlled Grid or the transmission services to be required by the SUDC. The Participating TO shall be responsible for coordinating with the ISO.

5.8 Information Sharing.

5.8.1 System Planning Studies.

The ISO, Participating TOs and SUDCs shall share available information such as projected SUDC Load growth and SUDC system expansions necessary for the ISO or the Participating TOs to conduct necessary system planning studies to the extent that such SUDC Load growth or SUDC system expansions will materially impact the operation of the ISO Control Area and the ISO Controlled Grid.

5.8.2 System Surveys and Inspections.

The ISO, each UDC and each SUDC shall cooperate, to the extent economically feasible for the SUDC, in performing system surveys and inspections regarding the operation of the ISO Control Area and the ISO Controlled Grid.

5.8.3 Reports.

5.8.3.1 The ISO shall make available to the SUDCs any public annual reviews or reports regarding performance standards, measurements and incentives relating to the ISO Control Area and the ISO Controlled Grid and shall also make available, upon reasonable notice, any such reports that the ISO receives from the Participating TOs. Each SUDC shall make available to the ISO upon request any public annual reviews or reports regarding performance standards, measurements and incentives relating to the SUDC's Distribution System to the extent these relate to the operation of the ISO Control Area and the ISO Controlled Grid.

5.8.3.2 The ISO and SUDCs shall develop an operating procedure for the ISO to record requests received from the SUDC for Maintenance Outages and the completion of the requested maintenance and turnaround times.

5.9 Installation of Equipment on and Rights of Access to SUDC Facilities.

5.9.1 Installation of Facilities.

The ISO and the SUDC shall each have the right on reasonable notice to install or to have installed equipment (including metering equipment) or other facilities on the property of the other, to the extent that such installation is necessary for the installing party to meet its service obligations unless to do so would have a negative impact on the reliability of the service provided by the party owning the property. The

ISO and the SUDC shall enter into agreements governing the installation of such equipment or other facilities containing customary, reasonable terms and conditions.

5.9.2 Access to Facilities.

The SUDCs shall grant, free of charge, the ISO reasonable access to SUDC facilities for purposes of inspection, repair, maintenance, or upgrading of facilities installed by the ISO on the SUDC's system, provided that the ISO must provide reasonable advance notice of its intent to access SUDC facilities and opportunity for SUDC staff to be present. Such access shall not be provided unless the parties mutually agree to the date, time and purpose of each access. Agreement on the terms of the access shall not be unreasonably withheld.

5.9.3 Access During Emergencies.

Notwithstanding any provision in this Section 5 the ISO may have access, without giving prior notice, to any SUDC's equipment or other facilities during times of a System Emergency.

5.9.4 Access For Audit Functions.

Notwithstanding any provision in this Section 5 the ISO may have access, without giving prior notice, to any SUDC's equipment or other facilities where the ISO has a reasonable basis to believe the SUDC has failed to comply with the SUDC Operating Agreement, applicable ISO Tariff or ISO Protocol provisions and access is required to conduct an audit to gather relevant facts.

6 COMMUNICATIONS.

6.1 Methods of Communications.

6.1.1 Full-Time Communications Facility Requirement.

Each Scheduling Coordinator, Utility Distribution Company, Participating Transmission Owner, Participating Generator, Control Area Operator (to the extent the agreement between the Control Area Operator and the ISO so provides), and Metered Subsystem Operator must provide a communications facility manned twenty-four (24) hours a day, seven (7) days a week capable of receiving Dispatch Instructions issued by the ISO.

6.1.2 Recording of Dispatch Instructions.

The ISO shall maintain records of all electronic, fax and verbal communications related to a Dispatch instruction. The ISO shall maintain a paper or electronic copy of all Dispatch instructions delivered by fax and all Dispatch instructions delivered electronically. The ISO shall record all voice conversations that occur related to Dispatch instructions on the Dispatch Instruction communication equipment. These records, copies and recordings may be used by the ISO to audit the Dispatch Instruction, and to verify the response of the Market Participant concerned to the Dispatch Instruction.

6.1.3 Contents of Dispatch Instructions.

Dispatch Instructions shall include the following information as appropriate:

- (a) exchange of operator names;
- (b) specific resource being Dispatched;
- (c) specific MW value and price point of the resource being Dispatched;
- (d) specific type of instruction (action required);
- (e) time the resource is required to begin initiating the Dispatch Instruction;
- (f) time the resource is required to achieve the Dispatch Instruction;
- (g) time of notification of the Dispatch Instruction; and
- (h) any other information which the ISO considers relevant.

6.2 Communications.

6.2.1 Communications between the ISO and Scheduling Coordinators shall take place via direct computer link to a dedicated terminal at the Scheduling Coordinator's scheduling center. If there is a failure of communications with a Scheduling Coordinator, then, at the ISO's discretion, the Scheduling Coordinator may communicate by facsimile, but only if the ISO and the Scheduling Coordinator have communicated by telephone in advance.

6.2.1A Normal verbal and electronic communication of Dispatch Instructions between the ISO and Generators will be via the relevant Scheduling Coordinator. Each Scheduling Coordinator must immediately pass on to the Generator concerned any communication for the Generator which it receives from the ISO. If the ISO considers that there has been a failure at a particular point in time or inadequate response over a particular period of time by the Generating Units to the Dispatch Instruction, the ISO will notify the relevant Scheduling Coordinator. The ISO may, with the prior permissions of the Scheduling Coordinator concerned, communicate with and give Dispatch Instructions to the operators of Generating Units and Loads directly without having to communicate through their appointed Scheduling Coordinator. In situations of deteriorating system conditions or emergency, the ISO reserves the right to communicate directly with the Generator(s) as required to ensure System Reliability.

6.3 Communication Protocols.

Communications between the ISO and Scheduling Coordinators shall be as described below:

6.3.1 Information Transfer from Scheduling Coordinator to ISO.

Unless otherwise agreed by the ISO, Scheduling Coordinators who wish to schedule or bid Ancillary Services to the ISO must submit the information by direct computer link. Scheduling Coordinators that wish to submit dynamic schedules or bids for Ancillary Services to the ISO must also comply with the applicable requirements of Sections 4.5.4.3, 8.4.5 and 8.4.7.3.2.

6.3.2 Submitting Information By Direct Computer Link.

For Scheduling Coordinators submitting information by direct computer link, each such Scheduling Coordinator shall establish a network connection with the ISO through the WEnet network. This shall be a permanent link with the ISO. Link initialization procedures shall be necessary to establish the connection for the first time, and to re-establish the connection each time the connection is restored after a system or communication failure. In order to log in, each Scheduling Coordinator shall furnish the ISO with user ID and password.

6.3.3 Information Transfer from ISO to Scheduling Coordinator.

Unless otherwise agreed between a Scheduling Coordinator and the ISO, the ISO shall furnish scheduling information to Scheduling Coordinators by electronic transfer as described in Sections 6.4.1 and 6.4.1.4. If electronic data transfer is not available, the information may be furnished by facsimile. If it is not possible to communicate with the Scheduling Coordinator using the primary means of communication, an alternate means of communication shall be selected by the ISO.

6.4 Transmission System Information and Communications

6.4.1 WEnet.

6.4.1A The ISO shall engage the services of an Internet Service Provider (ISP) to establish, implement and operate WEnet as a wide-band, wide-area backbone which is functionally similar to the Internet.

6.4.1A.1 WEnet provides the backbone on which any of three communications mechanisms will be utilized. These are:

- (a) use of a web browser such as Netscape;
- (b) use of File Transfer Protocol (FTP); or
- (c) use of an Application Programming Interface (API).

6.4.1A.2 Details of the technical aspects of each of these mechanisms, including information on how to change mechanisms and back-up procedures for individual Scheduling Coordinator failures, will be made available by the ISO to Scheduling Coordinators on request. It is assumed that each Scheduling Coordinator has made application for and signed a Scheduling Coordinator Agreement. As such, each Scheduling Coordinator will already be familiar with and have arranged the mechanism, including security arrangements, by which it will initially communicate with the ISO.

6.4.1A.3 The ISO Data Templates and Validation Rules document provides a description of the templates which will be utilized to enter data into the ISO's systems. For each of the three communications mechanisms, data entry is as follows:

- (a) direct entry of data into the template screens through the use of a browser;
- (b) upload of ASCII delimited text through use of an upload button on the template screens which activates the FTP mechanism; or
- (c) use of the Scheduling Coordinator's own API.

6.4.1B The ISO shall provide non-discriminatory access to information concerning the status of the ISO Controlled Grid by posting that information on the public access sites on WEnet, or other similar computer communications device, or by telephone or facsimile in the event of computer systems failure.

6.4.1B.1 WEnet will provide an interface for data exchange between the ISO and Scheduling Coordinators who shall each have individually assigned login accounts on WEnet.

6.4.1B.2 Through the use of the security provisions of WEnet, some data will be provided on a confidential basis (such as individual Scheduling Coordinator Schedules and bids) and other ISO data (such as ISO forecasts of Demand) will be published on the public section of WEnet and be available to anyone. The public information that the ISO provides over WEnet shall include, at a minimum, but not be limited to:

6.4.1.1 Advisory Information:

The following may be provided over such time scales as the ISO may in its discretion decide:

- (a) Future planned transmission Outages;
- (b) Generator Meter Multipliers.

6.4.1.2 Day-Ahead and Hour-Ahead Information:

- (a) Date;
- (b) Hour;
- (c) Total forecast Demand by UDC;

- (d) Inter-Zonal Congestion price per Congested path; Total Regulation and Reserve service capacity reservation cost by Zone;
- (e) Total capacity of Inter-Zonal Interfaces; and
- (f) Available capacity of Inter-Zonal Interfaces.

6.4.1.3 Ex Post Information:

- (a) Date;
- (b) Hour; and
- (c) Hourly Ex Post Price.

6.4.1.3A WEnet shall be used by the ISO to post Usage Charges for Inter-Zonal Interfaces within the ISO Controlled Grid.

6.4.1.3B WEnet shall serve as a bulletin board to enable Market Participants to inform one another of scheduling changes and trades made.

6.4.1.3C WEnet may be used by the ISO to communicate operating orders to the Scheduling Coordinators and other Market Participants, both in advance of actual operation and in real time. Such orders may include but are not limited to:

- (a) Notifying Scheduling Coordinators and other Market Participants to be on call to provide Non-Spinning Reserve and Replacement Reserves and Black Start;
- (b) Issuing start-up instructions;
- (c) Stating the amount of Spinning Reserves to be carried;
- (d) Requesting specific Ramping patterns;
- (e) Indicating which Scheduling Coordinators and other Market Participants are to provide Regulation;

- (f) Specifying the minimum amount of unloaded capacity that must be maintained in order to meet Regulation Requirements;
- (g) Issuing shut-down instructions; and
- (h) Specifying the voltage level and reactive reserve each Market Participant must maintain.

6.4.1.3D WEnet shall be used by the ISO to provide information to Market Participants regarding the ISO Controlled Grid. Such information may include but is not limited to:

- (a) Voltage control parameters;
- (b) ISO historical data for Congestion;
- (c) Forecasts of Usage Charges; and
- (d) Generation Meter Multipliers to support seven (7) day advance submission of Schedules by Scheduling Coordinators. Additional Generation Meter Multipliers may be published for different seasons and loading patterns.

6.4.1.4 Reliable Operation of the WEnet.

6.4.1.4.1 Market Participants shall arrange access to WEnet through the Internet Service Provider.

6.4.1.4.2 The ISO shall arrange for the Internet Service Provider to provide a pathway for public Internet connectivity through the WEnet backbone to accommodate users other than Market Participants without the need for a separate, dedicated user data link. This public Internet connection may provide a reduced level of data exchange and reduced information concerning the reliability and performance of the ISO Controlled Grid when compared to that provided to Market Participants through dedicated user data links.

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

Non-Spinning Reserve	MW	Hourly	\$/MW
Replacement Reserve	MW	Hourly	\$/MW
Black Start	MW	Annual	\$/MW

7 SYSTEM OPERATIONS UNDER NORMAL AND EMERGENCY OPERATING CONDITIONS.

7.1 ISO Control Center Operations.

7.1.1 ISO Control Center.

7.1.1.1 Establish ISO Control Center.

The ISO shall establish a WECC approved Control Area and control center to direct the operation of all facilities forming part of the ISO Controlled Grid, Reliability Must-Run Units and Generating Units providing Ancillary Services.

7.1.2 Establish Back-up Control Facility.

The ISO shall establish back-up control facilities remote from the ISO Control Center sufficient to enable the ISO to continue to direct the operation of the ISO Controlled Grid, Reliability Must-Run Units, System Resources and Generating Units providing Ancillary Services in the event of the ISO Control Center becoming inoperable.

7.1.3 ISO Control Center Authorities.

The ISO shall have full authority, subject to Section 4.2, to direct the operation of the facilities referred to in Section 7.1.2 including (without limitation), to:

- (a) direct the physical operation by the Participating TOs of transmission facilities under the Operational Control of the ISO, including (without limitation) circuit breakers, switches, voltage control equipment, protective relays, metering, and Load Shedding equipment;
- (b) commit and dispatch Reliability Must-Run Units, except that the ISO shall only commit Reliability Must-Run Generation for Ancillary Services capacity according to Section 30.6.1 of the Tariff;
- (c) order a change in operating status of auxiliary equipment required to control voltage or frequency;
- (d) take any action it considers to be necessary consistent with Good Utility Practice to protect against uncontrolled losses of Load or Generation and/or equipment damage resulting from unforeseen occurrences;
- (e) control the output of Generating Units, Interconnection schedules, and System Resources that are selected to provide Ancillary Services or Imbalance Energy;
- (f) Dispatch Curtailable Demand which has been scheduled to provide Non-Spinning Reserve or Replacement Reserve;
- (g) procure Supplemental Energy; and
- (h) require the operation of resources which are at the ISO's disposal in a System Emergency, as described in Section 7.4

The ISO will exercise its authority under this Section 7.1.3 by issuing Dispatch Instructions to the relevant Participants using the relevant communications method described in Section 34.3.6.

7.1.4 Primary ISO Control Center.

The Primary ISO Control Center shall have Operational Control over:

- (a) all transmission lines greater than 230kV and associated station equipment on the ISO Controlled Grid;
- (b) all Interconnections; and

(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.

The WECC set of standards for the Western Interconnection, which are based on the NERC standards.

The WECC further defines procedures and policies applicable to the Western Interconnection. WECC guidelines include:

- (i) Part 1 – Reliability Criteria for Transmission System Planning
 - (ii) Part 2 – Power Supply Design Criteria
 - (iii) Part 3 – Minimum Operating Reliability Criteria (MORC)
 - (iv) Part 4 – Definitions
- (b) Operating Procedures.

The WECC Operating Procedures submitted to WECC by individual utilities and the ISO to address specific operating problems in their respective grids that could affect operations of the interconnected grid.

- (c) Dispatcher's Handbook.

The WECC Dispatcher's Handbook supplied by WECC to all utilities and Control Areas as a reference for dispatchers to use during normal and emergency operations of the grid.

7.2.2.3.3 NERC Policies and Standards.

- (a) National Standards

The NERC national level standards for all utilities to follow to allow for safe and reliable operation of electric systems.

- (b) Operating Manual

The NERC Operating Manual supplied by NERC to all utilities and Control Areas as a reference for dispatchers to use during normal and emergency operations of the grid.

7.2.2.4 NAESB Standards. The following standards of the Wholesale Electric Quadrant (WEQ) of the North American Energy Standards Board (NAESB) are incorporated by reference:

- Coordinate Interchange (WEQ-004, Version 000, January 15, 2005, with minor corrections applied on March 25, 2005, and additional numbering added October 3, 2005) including Purpose, Applicability, and Standards 004-0 through 004-13, and 004-A through 004-D;
- Area Control Error (ACE) Equation Special Cases Standards (WEQ-005, Version 000, January 15, 2005, with minor corrections applied on March 25, 2005, and additional numbering added October 3, 2005) including Purpose, Applicability, and Standards 005-0 through 005-3.1.3, and 005-A;
- Inadvertent Interchange Payback (WEQ-007, Version 000, January 15, 2005, with minor corrections applied on March 25, 2005, and additional numbering added October 3, 2005) including Purpose, Applicability, and Standards 007-0 through 007-2, and 007-A; and
- Manual Time Error Correction – Time Error Initiation (WEQ-006-4, Version 000, with minor corrections applied on October 17, 2006).

The ISO has obtained a waiver of the following NAESB WEQ standards:

- Business Practices for Open Access Same-Time Information Systems (OASIS) (WEQ-001, Version 000, January 15, 2005, with minor corrections applied on March 25, 2005, and additional numbering added October 3, 2005) including Standards 001-0.2 through 001-0.8, 001-2.0 through 001-9.6.2, 001-9.8 through 001-10.8.6, and Examples 001-8.3-A, 001-9.2-A, 001-10.2-A, 001-9.3-A, 001-10.3-A, 001-9.4.1-A, 001-10.4.1-A, 001-9.4.2-A, 001-10.4.2-A, 001-9.5-A, 001-10.5-A, 001-9.5.1-A, and 001-10.5.1-A;

- Business Practices for Open Access Same-Time Information Systems (OASIS) Standards & Communication Protocols (WEQ-002, Version 000, January 15, 2005, with minor corrections applied on March 25, 2005, and additional numbering added October 3, 2005) including Standards 002-1 through 002-5.10;
and

- Open Access Same-Time Information Systems (OASIS) Data Dictionary (WEQ-003, Version 000, January 15, 2005, with minor corrections applied on March 25, 2005, and additional numbering added October 3, 2005) including Standard 003-0.

WECC has obtained a waiver of the following NAESB WEQ standard on its own behalf and on behalf of the Control Areas in the Western Interconnection, including the ISO:

- Manual Time Error Correction (WEQ-006, Version 000, January 15, 2005, with minor corrections applied on March 25, 2005, and additional numbering added October 3, 2005) including Purpose, Applicability, and Standards 006-0 through 006-12.

7.2.3 General Standard of Care. When the ISO is exercising Operational Control of the ISO Controlled Grid, the ISO and Market Participants shall comply with Good Utility Practice.

7.2.4 Routine Operation of the ISO Controlled Grid. The ISO shall operate the ISO Controlled Grid in accordance with the standards described in Section 7.2.2.3 and within the limit of all applicable Nomograms and established operating limits and procedures.

7.2.4.1 ISO Controlled Facilities.

7.2.4.1.1 General.

The ISO shall have Operational Control of all transmission lines and associated station equipment that have been transferred to the ISO Controlled Grid from the PTOs as listed in the ISO Register.

7.2.4.2 Clearing Equipment for Work.

The clearance procedures of the ISO and the relevant UDC and PTO must be adhered to by all parties, to ensure the safety of all personnel working on ISO Controlled Grid transmission lines and equipment. In accordance with Section 9.3, no work shall start on any equipment or line which is under the Operational Control of the ISO unless final approval has first been obtained from the appropriate ISO Control Center. Prior to starting the switching to return any line or equipment to service the ISO shall confirm that all formal requests to work on the cleared line or equipment have been released.

7.2.4.3 Equipment De-energized for Work.

In some circumstances, System Reliability requirements may require a recall capability that can only be achieved by allowing work to proceed with the line or equipment de-energized only (i.e. not cleared and grounded). Any personnel working on such de-energized lines and equipment must take all precautions as if the line or equipment were energized. Prior to energizing any such lines or equipment deenergized for work, the ISO shall confirm that all formal requests to work on the de-energized line or equipment have been released.

7.2.4.4 Hot-Line Work.

The ISO has full authority to approve requests by PTOs to work on energized equipment under the Operational Control of the ISO, and no such work shall be commenced until the ISO has given its approval.

7.2.4.5 Intertie Switching.

The ISO and the appropriate single point of contact for the relevant PTO and the adjacent Control Area shall coordinate during the de-energizing or energizing of any Interconnection.

7.2.4.6 Operating Voltage Control Equipment.

7.2.4.6.1 Operating Voltage Control Equipment Under ISO Control.

The ISO will direct each PTO's single point of contact in the operation of voltage control equipment that is under the ISO's Operational Control.

7.2.4.6.2 Operating Voltage Control Equipment Under UDC Control.

Each UDC must operate voltage control equipment under UDC control in accordance with existing UDC voltage control guidelines.

7.2.4.6.3 Special ISO Voltage Control Requirements.

The ISO may request a PTO via its single point of contact or a UDC via its single point of contact to operate under special voltage control requirements from time to time due to special system conditions.

7.3 Normal System Operations.

7.3.1 Actions for Maintaining Reliability of ISO Controlled Grid.

The ISO plans to obtain the control over Generating Units that it needs to control the ISO Controlled Grid and maintain reliability by purchasing Ancillary Services from the market auction for these services. When the ISO responds to events or circumstances, it shall first use the generation control it is able to obtain from the Ancillary Services bids it has received to respond to the operating event and maintain reliability. Only when the ISO has used the Ancillary Services that are available to it under such Ancillary Services bids which prove to be effective in responding to the problem and the ISO is still in need of additional control over Generating Units, shall the ISO assume supervisory control over other Generating Units. It is expected that at this point, the operational circumstances will be so severe that a real-time system problem or emergency condition could be in existence or imminent.

Each Participating Generator shall take, at the direction of the ISO, such actions affecting such Generator as the ISO determines to be necessary to maintain the reliability of the ISO Controlled Grid. Such actions shall include (but are not limited to):

- (a) compliance with the ISO's Dispatch instructions including instructions to deliver Ancillary Services in real time pursuant to the Final Day-Ahead Schedules and Final Hour-Ahead Schedules;
- (b) compliance with the system operation requirements set out in Section 7 of this ISO Tariff;
- (c) notification to the ISO of the persons to whom an instruction of the ISO should be directed on a 24-hour basis, including their telephone and facsimile numbers; and
- (d) the provision of communications, telemetry and direct control requirements, including the establishment of a direct communication link from the control room of the Generator to the ISO in a manner that ensures that the ISO will have the ability, consistent with this ISO Tariff and the ISO Protocols, to direct the operations of the Generator as necessary to maintain the reliability of the ISO Controlled Grid, except that a Participating Generator will be exempt from ISO requirements imposed in accordance with this subsection (d) with regard to any Generating Unit with a rated capacity of less than 10 MW, unless that Generating Unit is certified by the ISO to participate in the ISO's Ancillary Services and/or to submit Supplemental Energy bids.

7.4 Management of System Emergencies.

7.4.1 Declaration of System Emergencies.

The ISO shall, when it considers that conditions giving rise to a System Emergency exist, declare the existence of such System Emergency. A declaration by the ISO of a System Emergency shall be binding on all Market Participants until the ISO announces that the System Emergency no longer exists.

7.4.2 Emergency Procedures.

In the event of a System Emergency, the ISO shall take such action as it considers necessary to preserve or restore stable operation of the ISO Controlled Grid. The ISO shall act in accordance with Good Utility Practice to preserve or restore reliable, safe and efficient service as quickly as reasonably practicable.

The ISO shall keep system operators in adjacent Control Areas informed as to the nature and extent of the System Emergency in accordance with WECC procedures and, where practicable, shall additionally keep the Market Participants within the Control Area informed.

7.4.2.1 In the event of a System Emergency, UDCs shall comply with all directions from the ISO concerning the management and alleviation of the System Emergency and shall comply with all procedures concerning System Emergencies set out in this Tariff and the ISO Protocols, and each MSS Operator shall comply with all directions from the ISO concerning the avoidance, management and alleviation of the System Emergency and shall comply with all procedures concerning System Emergencies set forth in the ISO Tariff.

7.4.2.2 During a System Emergency, the ISO and UDCs shall communicate through their respective control centers and in accordance with procedures established in individual UDC operating agreements, and the ISO and the MSS Operator shall communicate through their respective control centers and in accordance with procedures established in the agreement through which the MSS Operator undertakes to the ISO to comply with the provisions of the ISO Tariff.

7.4.2.3 System Emergencies.

7.4.2.4 All Generating Units, System Units and System Resources that are owned or controlled by a Participating Generator are (without limitation to the ISO's other rights under this ISO Tariff) subject to control by the ISO during a System Emergency and in circumstances in which the ISO considers that a System Emergency is imminent or threatened. The ISO shall, subject to Section 7.4.4.1, have the authority to instruct a Participating Generator to bring its Generating Unit on-line, off-line, or increase or curtail the output of the Generating Unit and to alter scheduled deliveries of Energy and Ancillary Services into or out of the ISO Controlled Grid, if such an instruction is reasonably necessary to prevent an imminent or threatened System Emergency or to retain Operational Control over the ISO Controlled Grid during an actual System Emergency. The ISO shall have the authority to instruct an RMR Unit whose owner has selected Condition 2 of its RMR Contract to start-up and change its output if the ISO has reasonably used all other available and effective resources to prevent a threatened System Emergency

without declaring that a System Emergency exists. If the ISO so instructs a Condition 2 RMR Unit, it shall compensate that unit in accordance with Section 11.2.4.2 and allocate the costs in accordance with Section 11.2.4.2.1.1.

7.4.3.1 Notifications by ISO of System Conditions.

The ISO will provide the following notifications to Participants to communicate unusual system conditions or emergencies.

7.4.3.2 System Alert.

ISO will give a system Alert Notice 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.

7.4.3.3 System Warning.

The ISO will give a system warning notice when the operating requirements for the ISO Controlled Grid are not being 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 is not acceptable for the Applicable Reliability Criteria. This system warning notice will notify Participants that the ISO will, acting in accordance with Good Utility Practice, take such steps as it considers necessary to ensure compliance with Applicable Reliability Criteria, including the negotiation of Generation through processes other than competitive bids.

7.4.3.4 System Emergency.

When, in the judgment of the ISO, the System Reliability of the ISO Controlled Grid is in danger of instability, voltage collapse or under-frequency caused by transmission or Generation trouble in the ISO Control Area, or events outside of the ISO Control Area that could result in a cascade of events throughout the WECC grid, the ISO will declare a System Emergency. This declaration may include a notice to suspend the Day-Ahead, Hour-Ahead and Real Time Markets, authorize full use of Black Start

Generation, initiate full control of manual Load Shedding, authorize the curtailment of Curtailable Demand (even though not scheduled as an Ancillary Service). The ISO will reduce the System Emergency declaration to a lower alert status when it is satisfied, after conferring with Reliability Coordinators within the WECC that the major contributing factors have been corrected, all involuntarily interrupted Demand is back in service (except interrupted Curtailable Demand selected as an Ancillary Service). This reduction in alert status will reinstate the competitive markets if they have been suspended.

7.4.4 Intervention in Market Operations.

The ISO may intervene in the operation of the Day-Ahead Market, the Hour-Ahead Market or the Real Time Market and set the Administrative Price, if the ISO determines that such intervention is necessary in order to contain or correct a System Emergency as follows.

7.4.4.1 The ISO will not intervene in the operation of the Day-Ahead Market unless there has been a total or major collapse of the ISO Controlled Grid and the ISO is in the process of restoring it. The ISO shall, where reasonably practicable, utilize Ancillary Services which it has the contractual right to instruct and which are capable of contributing to containing or correcting the actual, imminent or threatened System Emergency prior to issuing instructions to a Participating Generator under Section 7.4.2.4.

7.4.4.2 Before any such intervention the ISO must (in the following order): (a) dispatch all scheduled Generation and all other Generation offered or available to it regardless of price (including all Adjustment Bids, Supplemental Energy bids, Ancillary Services and reserves); (b) dispatch all interruptible Loads made available by UDCs to the ISO in accordance with the relevant agreements with UDCs; (c) dispatch or curtail all price-responsive Demand that has been bid into any of the markets and exercise its rights under all load curtailment contracts available to it; (d) exercise Load Shedding to curtail Demand on an involuntary basis to the extent that the ISO considers necessary.

7.4.4.3 The Administrative Price in relation to each of the markets for Imbalance Energy and Ancillary Services shall be set at the applicable Market Clearing Price in the Settlement Period

immediately preceding the Settlement Period in which the intervention took place. When Administrative Prices are imposed, Inter-Zonal Congestion will be managed in accordance with Section 27.1.1.6(c).

7.4.4.4 The intervention will cease as soon as the ISO has restored all Demand that was curtailed on an involuntary basis under Section 7.4.4.2(d).

7.4.5 Emergency Guidelines.

The ISO shall issue protocols for all Market Participants to follow during a System Emergency. These guidelines shall be consistent with the specific obligations of Scheduling Coordinators and Market Participants referenced in Sections 7.4.10, 7.4.11, 7.4.2, 7.4.2.4 and 7.4.4.1 of this tariff. All Participants shall respond to ISO Dispatch Instructions with an immediate response during System Emergencies.

7.4.6 The ISO shall in accordance with Section 7.4.5 hereof implement the Electrical Emergency Plan in consultation with the UDCs, the MSS Operator, or other entities, at the ISO's discretion, when Energy reserve margins are forecast to be at the levels specified in the plan.

7.4.6.1 Each UDC and MSS Operator will notify its End-Use Customers connected to the UDC's or the MSS's Distribution System of any voluntary curtailments notified to the UDC or to the MSS Operator by the ISO pursuant to the provisions of the EEP.

7.4.7 Periodic Tests of Emergency Procedures.

The ISO shall develop and administer periodic unannounced tests of System Emergency procedures. Such tests shall be designed to ensure that the ISO Market Participants are capable of promptly and efficiently responding to imminent or actual System Emergencies.

7.4.8 Prioritization Schedule for Shedding and Restoring Load.

Prior to the ISO Operations Date, and annually thereafter, the ISO shall, in consultation with Market Participants and subject to the provisions of Section 3, develop a prioritization schedule for Load Shedding should a System Emergency require such action. The prioritization schedule shall also establish a sequence for the restoration of Load in the event that multiple Scheduling Coordinators or Market Participants are affected by service interruptions and Load must be restored in blocks. For Load

shed in accordance with Section 7.4.11.4.2, the prioritization schedule will only include those UDCs or MSS Operators that have Scheduling Coordinators that are scheduling insufficient resources to meet the Load in the UDC or MSS Service Area. For Load shed in accordance with Section 7.4.11.4.3, the prioritization schedule will include all UDCs and MSS Operators.

7.4.9 Under Frequency Load Shedding (UFLS).

7.4.9.1 Each UDC's agreement with the ISO and each agreement through which the MSS Operator undertakes to the ISO to comply with the provisions of the ISO Tariff shall describe the UFLS program for that UDC or for that MSS. The ISO and UDC or the ISO and the MSS shall review the UFLS program periodically to ensure compliance with Applicable Reliability Criteria.

7.4.9.2 The ISO shall perform periodic audits of each UDC's UFLS system and of each MSS's UFLS system to verify that the system is properly configured for each UDC or MSS.

7.4.9. The ISO will use its reasonable endeavors to ensure that UFLS is coordinated among the UDCs and MSSs so that no UDC bears a disproportionate share of the ISO's UFLS program.

7.4.9.4 In compiling its UFLS program, the ISO, at its discretion, may also coordinate with other entities, review and audit their UFLS programs and systems as described in Section Sections 7.4.9.1 to 7.4.9.3.

7.4.10 Further Obligations Relating to System Emergencies.

The ISO and Participating TOs shall comply with their obligations in Section 9 of the TCA.

7.4.11 Use of Load Curtailment Programs.

7.4.11.1 Use of UDC's Existing Load Curtailment Programs.

As an additional resource for managing System Emergencies, the ISO will, subject to Section 3, notify the UDCs when the conditions to implement their Load curtailment programs have been met in accordance with their terms. The UDCs will exercise their best efforts, including seeking any necessary regulatory approvals, to enable the ISO to rely on their curtailment rights at specified levels of Operating Reserve. Each UDC shall by not later than October 1 of each year advise the ISO of the capabilities of its Load

curtailment programs for the forthcoming year, and the conditions under which those capabilities may be exercised and shall give the ISO as much notice as reasonably practicable of any change to such programs.

7.4.11.2 Load Curtailment.

A Scheduling Coordinator may specify that Loads will be reduced at specified Market Clearing Prices or offer the right to exercise Load curtailment to the ISO as an Ancillary Service or utilize Load curtailment itself (by way of self-provision of Ancillary Services) as Non-Spinning Reserve or Replacement Reserve. The ISO, at its discretion, may require direct control over such Curtailable Demand to assume response capability for managing System Emergencies. However, non-firm Loads shall not be eligible to provide Curtailable Demand if they are receiving incentives for interruption under existing programs approved by a Local Regulatory Authority, unless: a) participation in the ISO's Ancillary Services markets is specifically authorized by such Local Regulatory Authority, and b) there exist no contingencies on the availability, nor any unmitigated incentives encouraging prior curtailment, of such interruptible Load for Dispatch as Curtailable Demand as a result of the operation of such existing program. The ISO may establish standards for automatic communication of curtailment instructions to implement Load curtailment as a condition for accepting any offered Load curtailment as an Ancillary Service.

7.4.11.3 The ISO shall have the authority to direct a UDC or an MSS Operator to disconnect Load from the ISO Controlled Grid if necessary to avoid an anticipated System Emergency or to regain operational control over the ISO Controlled Grid during an actual System Emergency. The ISO shall direct the UDCs or the MSS Operator to shed Load in accordance with the prioritization schedule developed pursuant to Section 7.4.8. When ISO Controlled Grid conditions permit restoration of Load, the ISO shall restore Load according to the prioritization schedule developed pursuant to Section 7.4.8 hereof. The MSS Operator shall restore Load internal to the MSS.

7.4.11.4 Load Shedding.

7.4.11.4.1 A portion of the ISO forecast of Control Area Load for each Trading Day will be allocated to each UDC or MSS Service Area. The ISO will aggregate each Scheduling Coordinator's

Day-Ahead Schedules to Load in each UDC or MSS Service Area and will compare those aggregated Load Schedules to the ISO's Control Area Load forecast of metered Demand for that UDC or MSS Service Area to determine if the Load in the UDC or MSS Service Area has a resource deficiency based on the Day-Ahead Schedules.

7.4.11.4.2 If the ISO forecasts in advance of the Hour-Ahead Market that Load curtailment will be necessary due to a resource deficiency, the ISO will identify any UDC or MSS Service Area that is resource deficient. The ISO will provide notice to all Scheduling Coordinators if one or more UDC or MSS is deficient. If Load curtailment is required to manage a System Emergency associated with insufficient Hour-Ahead Schedules of resources, the ISO will determine the amount and location of Load to be curtailed and will allocate a portion of that required Load curtailment to each UDC or MSS Operator whose Service Area has been identified, based on Hour-Ahead Schedules, as being resource-deficient based on the ratio of its resource deficiency to the total Control Area resource deficiency. Each UDC or MSS Operator shall be responsible for notifying its customers and Generators connected to its system of curtailments and service interruptions.

7.4.11.4.3 If a Load curtailment is required to manage System Emergencies, in any circumstances other than those described in Section 7.4.11.4.2, the ISO will determine the amount and location of Load to be reduced and to the extent practicable, will allocate a portion to each UDC based on the ratio of its Demand (at the time of the Control Area annual peak for the previous year) to total Control Area annual peak Demand for the previous year taking into account system considerations and the UDC's curtailment rights under their tariffs. Each UDC or MSS Operator shall be responsible for notifying its customers and Generators connected to its system of curtailments and service interruption.

7.4.12 Curtailment under Emergency and Non-Emergency Conditions.

7.4.12.1 Emergency Conditions.

To the extent practicable, the ISO shall allocate necessary curtailments of Existing Rights or Non-Converted Rights under emergency conditions in accordance with the instructions submitted by the Responsible PTO pursuant to Section 16.2.4A.1. If circumstances prevent the ISO's compliance with

such instructions, the ISO shall allocate such curtailments in a non-discriminatory manner consistent with Good Utility Practice.

7.4.12.2 Non-Emergency Conditions.

Unless otherwise specified by the Responsible PTO in the instructions that it submits to the ISO under Section 16.2.4A.1, the ISO will allocate any necessary curtailments under non-emergency conditions, pro rata, among holders of Existing Rights, at particular Scheduling Points and/or on particular contract paths, in the order of: (1) non-firm, (2) each priority of conditional firm, and (3) each priority of firm rights. Priorities for firm and conditional firm transmission service are indicated using contract usage templates, as described in Section 30.2.7.

7.4.13 System Emergency Reports and Sanctions.

7.4.13.1 Review of Major Outages.

The ISO with the cooperation of any affected UDC shall jointly perform a review following a major Outage that affects at least ten (10) percent of the Load served by the Distribution System of a UDC or any Outage that results in major damage to the ISO Controlled Grid or to the health and safety of personnel. The review shall address the cause of the Outage, the response time and effectiveness of emergency management efforts, and whether the operation, maintenance or scheduling practices of the ISO, any Participating TOs, Eligible Customers, UDCs or Participating Generators enhanced or undermined the ability of the ISO to maintain or restore service efficiently and in a timely manner.

7.4.13.2 Provide Information to Review Outages.

Participating TOs, Participating Generators, Eligible Customers, Scheduling Coordinators and UDCs shall promptly provide information requested by the ISO to review Outages pursuant to Section 7.4.13.1 and to prepare Outage reports. The ISO shall seek the views of any affected Participating TOs, Participating Generators, Eligible Customers, Scheduling Coordinator or UDCs and allow such affected Participating TOs, Participating Generators, Eligible Customers, Scheduling Coordinators or UDCs to comment on any issues arising during the preparation of a report. All findings and reports arising from the ISO's review shall be shared with Participating TOs, Participating Generators, Eligible Customers and UDCs.

7.4.13.3 Imposing Sanctions.

If the ISO finds that the operation and maintenance practices of any Participating TOs, Participating Generators, Eligible Customers, or UDCs prolonged the response time or contributed to the Outage, the ISO may impose sanctions on the responsible Participating TOs, Participating Generators, Eligible Customers, or UDCs provided that no sanction shall be imposed in respect of actions taken in compliance with the ISO's instructions or pursuant to a Remedial Action Scheme. The ISO shall develop and file with FERC a schedule of such sanctions. Any dispute concerning whether sanctions should be imposed under this Section shall be resolved through the ISO ADR Procedures. The schedule of sanctions filed with FERC (including categories and levels of sanctions) shall not be subject to the ISO ADR Procedures. The ISO shall publish on the ISO Home Page details of all instances in which a sanction has been imposed.

7.4.14 ISO Facilities and Equipment.

7.4.14.1 ISO Facility and Equipment Outages.

The ISO has installed redundant control centers, communication systems and computer systems. Most, but not necessarily all, equipment problems or failures should be transparent to Participants. This Section 7.4.14.1 addresses some situations when Participants could be affected, but it is impossible to identify and plan for every type of equipment problem or failure. Real time situations will be handled by the real time ISO dispatchers. The ISO control room in Folsom is the Primary ISO Control Center and the ISO control room in Alhambra is the Backup ISO Control Center.

7.4.14.2 WEnet Unavailable.

7.4.14.2.1 Unavailable Critical Functions of WEnet.

During a total disruption of the WEnet several critical functions of the ISO will not be available including:

- (a) the Scheduling Infrastructure (SI) computer will not be able to communicate with Scheduling Coordinators to receive any type of updated Schedule information;

- (b) the SI computer will not be able to communicate Congestion Management information and Schedule changes to the Scheduling Coordinators; and
- (c) the ISO will not be able to communicate general information, including emergency information, to any Participants.

7.4.14.2.2 Communications during WEnet Unavailability.

During any period of WEnet unavailability, the ISO shall:

- (a) make all reasonable efforts to keep Participants aware of current ISO Controlled Grid status using voice communications;
- (b) use the most recent set of Balanced Schedules for each Scheduling Coordinator for the current and all future Settlement Periods and/or Trading Days until the WEnet is restored; and
- (c) attempt to take critical Schedule changes from Scheduling Coordinators via voice communications as time and manpower allows.

7.4.14.2.3 Primary ISO Control Center – Loss of all Voice Communications.

In the event of loss of all voice communication at the Primary ISO Control Center, the Primary ISO Control Center will use alternate communications to notify the Backup ISO Control Center of the loss of voice communications. The Backup ISO Control Center will post information on the situation on the WEnet. Additional voice notifications will be made as time permits. Once voice communications have been restored to the Primary ISO Control Center, the ISO will post this information on the WEnet.

7.4.14.2.4 Primary ISO Control Center – Control Center Completely Unavailable.

In the event that the Primary ISO Control Center becomes completely unavailable, the Primary ISO Control Center will use alternate communications to notify the Backup ISO Control Center that the Primary ISO Control Center is unavailable. The Backup ISO Control Center will post information on the situation on the WEnet. Additional voice notifications will be made as time permits.

The Backup ISO Control Center will post confirmation on the WEnet that all computer systems are functioning normally (if such is the case) and take complete control of the ISO Controlled Grid. The Backup ISO Control Center will notify the TOC by direct voice communication of the situation.

Once the Primary ISO Control Center is again available, all functions will be transferred back, and the Primary ISO Control Center will notify all Participants via the WEnet.

7.4.14.2.5 Primary ISO Control Center - ISO Energy Management System (EMS) Unavailable.

Should an outage occur to the redundant EMS computer systems in the Primary ISO Control Center, an auto transfer should occur to transfer EMS operation to the redundant EMS back up computers at the Backup ISO Control Center. Due to the severity of a total ISO EMS computer outage, the Primary ISO Control Center will post information on the WEnet that the Primary ISO Control Center EMS computer is unavailable and that EMS control has been transferred to the Backup ISO Control Center.

When the Primary ISO Control Center EMS computer is restored, the Backup ISO Control Center will initiate a transfer back of the EMS system to the Primary ISO Control Center. The Primary ISO Control Center will post information on the restored EMS computer system status on the WEnet.

7.4.14.2.6 Backup ISO Control Center – Loss of all Voice Communications.

In the event of a loss of all voice communications at the Backup ISO Control Center, the Backup ISO Control Center will use alternate communications to notify the Primary ISO Control Center of the loss of voice communications. The Primary ISO Control Center will post information on the situation via the WEnet. Additional voice notifications will be made as time permits.

Once voice communications have been restored to the Backup ISO Control Center, the Primary ISO Control Center will post this information on the WEnet.

7.4.14.2.7 Backup ISO Control Center – Control Center Completely Unavailable.

In the event that the Backup ISO Control Center becomes completely unavailable, the Backup ISO Control Center will use alternate communications to notify the Primary ISO Control Center that the

Backup ISO Control Center is unavailable. The Primary ISO Control Center will post information on the situation on the WEnet. Additional voice notifications will be made as time permits.

The Primary ISO Control Center will post confirmation on the WEnet that all computer systems are functioning normally (if such is the case) and take complete control of the ISO Controlled Grid. The Primary ISO Control Center will notify the SCE GCC by direct voice communications of the situation.

Once the Backup ISO Control Center is again available all functions will be transferred back, and the Backup ISO Control Center will notify all Participants via the WEnet.

7.4.14.2.8 Use of IOUs' Energy Control Center Computers.

The ISO and the IOUs will comply with the procedures for the utilization by the ISO of the IOUs' Energy control center computers when developed. The ISO will post such procedures on the WEnet when agreed.

7.5 Management of Overgeneration Conditions.

The ISO's management of Overgeneration relates only to real time. In the event that Overgeneration conditions occur during real time, the ISO will direct the Scheduling Coordinators to take the steps described in this Section 7.5 of the ISO Tariff and Scheduling Coordinators shall implement ISO directions without delay. Overgeneration in real time will be mitigated by the ISO as follows; provided that the ISO Operator will have the discretion, if necessary to avoid a System Emergency, to eliminate one or more of the following steps.

7.5.1 Commencing one hour prior to the start of the Settlement Period, the ISO will, based on available Adjustment Bids, Supplemental Energy bids and Ancillary Service Energy bids, issue Dispatch instructions to Scheduling Coordinators to reduce Generation and imports for the next operating hour.

7.5.2 To the extent that there are insufficient decremental Energy bids available for the operating hour to fully mitigate the Overgeneration condition, the ISO will notify Scheduling Coordinators of the projected amount of Overgeneration to be mitigated in that hour.

7.5.3 In addition to the action taken under 7.5.2, the ISO will, if it considers it necessary to maintain the reliable operation of the ISO Control Area, offer Energy for sale on behalf of Scheduling Coordinators to adjacent Control Area operators at the estimated BEEP Interval Ex Post Price or, if the ISO considers it necessary, at a price established by the ISO on behalf of Scheduling Coordinators, to be paid to adjacent Control Area operators.

7.5.4 To the extent that the steps described in Sections 7.5.1 through 7.5.3 fail to mitigate Overgeneration, the ISO will instruct Scheduling Coordinators to reduce either Generation, or imports, or both. The amount of the reduction for each Scheduling Coordinator will be calculated pro rata based on the product of the total required reduction in Generation and imports (or increase in exports) and the ratio of its Demand to the total Demand in the ISO Control Area.

7.5.5 To the extent that the above steps fail to fully mitigate the Overgeneration, the ISO will issue mandatory Dispatch instructions for specific reductions in Generating Unit output and external imports and all relevant Scheduling Coordinators shall be obligated to comply with such Dispatch instructions.

7.5.6 Any costs incurred by the ISO in implementing Section 7.5.3 shall be reimbursed to the ISO by Scheduling Coordinators based upon the extent to which they supplied Energy, in metered amounts, greater than the Generation and imports scheduled in their Final Schedules and consumed Energy, in metered amounts, less than the Demand scheduled in their Final Schedules, as a proportion of the total amount of such excess or shortfall among all Scheduling Coordinators.

8. ANCILLARY SERVICES.

8.1 Scope.

The ISO shall be responsible for ensuring that there are sufficient Ancillary Services available to maintain the reliability of the ISO Controlled Grid consistent with WECC and NERC criteria. The ISO's Ancillary Services requirements may be self-provided by Scheduling Coordinators. Those Ancillary Services which the ISO requires to be available but which are not being self-provided will be competitively procured by the ISO from Scheduling Coordinators in the Day-Ahead Market, Hour-Ahead Market and in real time or

by longer-term contracts. The ISO will manage both ISO procured and self-provided Ancillary Services as part of the real-time Dispatch. The ISO will calculate payments for Ancillary Services to Scheduling Coordinators and charge the cost to Scheduling Coordinators.

For purposes of this ISO Tariff, Ancillary Services are: (i) Regulation, (ii) Spinning Reserve, (iii) Non-Spinning Reserve, (iv) Replacement Reserve, (v) Voltage Support, and (vi) Black Start capability. Bids for Non-Spinning Reserve and Replacement Reserve may be submitted by the Demand-side as well as by owners of Generation. Bids for Regulation, Spinning Reserve, Non-Spinning Reserve, and Voltage Support may be submitted by a Scheduling Coordinator for other non-generation resources that are capable of providing the specific service and that meet applicable Ancillary Service standards and technical requirements, as set forth in Sections 8.1 through 8.4, and are certified by the ISO to provide Ancillary Services. The provision of Regulation, Spinning Reserve, Non-Spinning Reserve, and Voltage Support by other non-generation resources is subject to the same requirements applicable to other providers of these Ancillary Services, as set forth in Sections 8.5 through 8.14. Identification of specific services in this ISO Tariff shall not preclude development of additional interconnected operation services over time. The ISO and Market Participants will seek to develop additional categories of these unbundled services over time as the operation of the ISO Controlled Grid matures.

8.2 Ancillary Services Standards.

All Ancillary Services shall meet the ISO's Ancillary Services standards.

8.2.1 Determination of Ancillary Service Standards.

The ISO shall set the required standard for each Ancillary Service necessary to maintain the reliable operation of the ISO Controlled Grid. Ancillary Services standards shall be based on WECC Minimum Operating Reliability Criteria (MORC), NERC and ISO Controlled Grid reliability requirements. The ISO Grid Operations Committee, in conjunction with the relevant reliability council (WECC), shall develop these Ancillary Services standards to determine reasonableness, cost effectiveness, and adherence to NERC and WECC standards. The standards developed by the ISO shall be used as a basis for determining the quantity and type of each Ancillary Service which the ISO requires to be available. These requirements and standards apply to all Ancillary Services whether self-provided or procured by the ISO.

8.2.2 Time-frame For Revising Ancillary Service Standards.

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

revisions to WECC and NERC standards. The ISO may adjust the Ancillary Services standards temporarily to take into account, among other things variations in system conditions, real-time Dispatch constraints, contingencies, and voltage and dynamic stability assessments. Where practicable, the ISO will provide notice, via the ISO Home Page, of any temporary adjustments to Ancillary Service standards by 6:00 p.m. two days ahead of the Trading Day to which the adjustment will apply. Periodic reviews by the ISO Grid Operations Committee or the ISO Technical Advisory Committee may include, but are not limited to: (a) analysis of the deviation between actual and forecast Demand; (b) analysis of patterns of unplanned Generating Unit Outages; (c) analysis of compliance with NERC and WECC Criteria; (d) analysis of operation during system disturbances; (e) analysis of patterns of shortfalls between Final Day-Ahead Schedules and actual Generation and Demand; and (f) analysis of patterns of unplanned transmission Outages.

8.2.3 Quantities of Ancillary Services Required.

For each of the Ancillary Services, the ISO shall determine the quantity and location of the Ancillary Service which is required and which must be under the direct Dispatch control of the ISO on an hourly basis each day. The ISO shall determine the quantities it requires as follows:

8.2.3.1 Regulation Service.

The ISO shall maintain sufficient Generating Units immediately responsive to AGC in order to provide sufficient Regulation service to allow the ISO Control Area to meet WECC and NERC control performance criteria by continuously balancing Generation to meet deviations between actual and scheduled Demand and to maintain interchange schedules. The quantity of Regulation capacity needed for each Settlement Period of the Day-Ahead Market and the Hour-Ahead Markets shall be determined as a percentage of the aggregate scheduled Demand for that Settlement Period.

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

(b) Publication of Estimated Regulation Percentage for Day-Ahead Market. In accordance with the requirements of Appendix Y, the ISO will publish on WEnet its estimate of the percentage it will use for determining the quantity of Regulation it requires for each Settlement Period of the Day-Ahead Market for that Trading Day.

(c) Publication of Estimated Regulation Percentage for Hour-Ahead Market. The ISO will publish on WEnet its estimate of the percentage it will use to determine the quantity of Regulation it requires for each Hour-Ahead Market.

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

8.2.3.2 Spinning And Non-Spinning Reserves.

The ISO shall maintain minimum contingency Operating Reserve made up of Spinning Reserve and Non-Spinning Reserve in accordance with WECC MORC criteria equal to (a) 5% of the Demand (except the Demand covered by firm purchases from outside the ISO Control Area) to be met by Generation from hydroelectric resources plus 7% of the Demand (except the Demand covered by firm purchases from outside the ISO Control Area) to be met by Generation from other resources, or (b) the single largest Contingency, if this is greater or (c) by reference to such more stringent criteria as the ISO may determine from time to time. The Spinning Reserve component of Operating Reserve shall be no less than one-half the Operating Reserve required for each Settlement Period of the Day-Ahead Market, the Hour-Ahead Market and the Real Time Market. When the level of Operating Reserve is determined by Demand, the ISO shall not maintain Operating Reserve with respect to Demand covered by firm purchases from outside the ISO Control Area. In addition, the ISO shall maintain Operating Reserve equal to the total amount of: (i) Interruptible Imports scheduled by Scheduling Coordinators for any hour and, (ii) on demand obligations of Scheduling Coordinators (i.e., the demand obligations to other entities or Control Areas that the Scheduling Coordinator is to provide from resources within the ISO Controlled Grid). Such additional Operating Reserve is the responsibility of the Scheduling Coordinator either scheduling

interruptible imports or with on demand obligations and such additional Operating Reserve must either be self-provided or purchased from the ISO by Scheduling Coordinators. To the extent such additional Operating Reserve is self-provided by a Scheduling Coordinator, it may consist entirely of Non-Spinning Reserve. To the extent that such additional Operating Reserve is not self-provided by a Scheduling Coordinator, the ISO will procure the necessary amounts of Operating Reserve, but not necessarily entirely from Non-Spinning Reserve.

8.2.3.3 Replacement Reserve.

The ISO needs sufficient Replacement Reserve to be available to allow restoration of dispatched Operating Reserve to its Set Point within sixty minutes. The ISO shall make its determination of the required quantity of Replacement Reserve based on:

- (a) historical analysis of the deviation between actual and Day-Ahead forecast Demand,
- (b) historical patterns of unplanned Generating Unit Outages,
- (c) historical patterns of shortfalls between Final Day-Ahead Schedules and actual Generation and Demand,
- (d) historical patterns of unexpected transmission Outages, and
- (e) such other factors affecting the ability of the ISO to maintain System Reliability as the ISO may from time to time determine.

The ISO shall have discretion to determine the quantity of Replacement Reserve it requires in each Zone.

8.2.3.4 Voltage Support.

The ISO shall determine on an hourly basis for each day the quantity and location of Voltage Support required to maintain voltage levels and reactive margins within WECC and NERC criteria using a power flow study based on the quantity and location of scheduled Demand. The ISO shall issue daily voltage schedules (Dispatch instructions) to Participating Generators, Participating TOs and UDCs, which are required to be maintained for ISO Controlled Grid reliability. All other Generating Units shall comply with the power factor requirements set forth in contractual arrangements in effect on the ISO Operations Date,

or, if no such contractual arrangements exist and the Generating Unit exists within the system of a Participating TO, the power factor requirements applicable under the Participating TO's TO Tariff or other tariff on file with the FERC.

All Participating Generators shall maintain the ISO specified voltage schedule at the transmission interconnection points to the extent possible while operating within the power factor range specified in their interconnection agreements or, for Regulatory Must-Take Generation, Regulatory Must-Run Generation and Reliability Must-Run Generation consistent with existing obligations. For Generating Units, that do not operate under one of these agreements, the minimum power factor range will be within a band of 0.90 lag (producing VARs) and 0.95 lead (absorbing VARs) power factors. Participating Generators with Generating Units existing at the ISO Operations Date that are unable to meet this operating power factor requirement may apply to the ISO for an exemption. Prior to granting such an exemption, the ISO shall require the Participating TO or UDC to whose system the relevant Generating Units are interconnected to notify it of the existing contractual requirements for Voltage Support established prior to the ISO Operations Date for such Generating Units. Such requirements may be contained in CPUC Electric Rule 21 or the Interconnection Agreement with the Participating TO or UDC. The ISO shall not grant any exemption under this Section from such existing contractual requirements. The ISO shall be entitled to instruct Participating Generators to operate their Generating Units at specified points within their power factor ranges. Participating Generators shall receive no compensation for operating within these specified ranges.

If the ISO requires additional Voltage Support, it shall procure this either through Reliability Must-Run Contracts or, if no other more economic sources are available by instructing a Generating Unit to move its MVar output outside its mandatory range. Only if the Generating Unit must reduce its MW output in order to comply with such an instruction will it be compensated in accordance with Section 8.5.9.

All Loads directly connected to the ISO Controlled Grid shall maintain reactive flow at grid interface points within a specified power factor band of 0.97 lag to 0.99 lead. Loads shall not be compensated for the service of maintaining the power factor at required levels within the bandwidth. A

UDC interconnecting with the ISO Controlled Grid at any point other than a Scheduling Point shall be subject to the same power factor requirement.

The power factor for both the Generating Units and Loads shall be measured at the interconnection point with the ISO Controlled Grid. The ISO will develop and will be authorized to levy penalties against Participating Generators, UDCs or Loads whose Voltage Support does not comply with the ISO's requirements. The ISO will establish voltage control standards with UDCs and the operators of other Control Areas and will enter into operational agreements providing for the coordination of actions in the event of a voltage problem occurring.

Wheeling Through and Wheeling Out transactions may also be subject to a reactive charge as developed by the ISO. If the ISO shall determine that a reactive charge should be payable at a future date, it shall, subject to FERC acceptance and approval, publish annually the Voltage Support obligations and applicable charges for Wheeling Through and Wheeling Out transactions at Scheduling Points. The obligations shall be predetermined by the ISO based on the estimated amount of the Wheeling Through and Wheeling Out transactions each year.

8.2.3.5 Black Start Capability.

The ISO shall determine the amount and location of Black Start Generation it requires through contingency studies that are used as the basis of the ISO's emergency plans. The studies shall specify:

- (a) the initiating disturbance;
- (b) the magnitude of the Outage, including the extent of the Outage (local area, ISO Controlled Grid, or WECC), the assumed status of Generation after the initiating disturbance, the status of interconnections, the system Demand level at the time of the disturbance, the interconnection support, and assumptions regarding the availability of support from other utilities to help restore Generation and Demand;
- (c) the Generator performance including a percentage of Black Start units (to be determined by the ISO) which are expected to fail to start, and;

(d) expected transmission system damage.

The ISO shall also specify the following load restoration performance goals:

- (i) Black Start unit startup and connection times;
- (ii) ISO Controlled Grid restoration times; and
- (iii) load restoration times.

Scheduling Coordinators shall provide the ISO with their load restoration time requirements for any Loads that provide emergency services.

8.2.3.6 The ISO, whenever possible, will increase its purchases of an Ancillary Service that can substitute for another Ancillary Service, when doing so is expected to reduce its total cost of procuring Ancillary Services while meeting reliability requirements. The ISO will make such adjustments in accordance with the following principles:

- (a) The Regulation requirement must be satisfied by Regulation bids from Resources qualified to provide Regulation;
- (b) Additional Regulation capacity can be used to satisfy requirements for any type of reserves (Spinning Reserve, Non-Spinning Reserve or Replacement Reserve);
- (c) Regulation and Spinning Reserve requirements must be satisfied by the combination of Regulation and Spinning Reserve bids. Spinning Reserve and Regulation may be provided as separate services from the same Generating Unit, provided that the sum of Spinning Reserve and Regulation provided is not greater than the maximum ramp rate of the Generating Unit (MW/minute) times ten;
- (d) Additional Regulation and Spinning Reserve capacity can be used to satisfy requirements for Non-Spinning and Replacement Reserve, except that any Spinning Reserve capacity that 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 cannot be used to satisfy requirements for Replacement Reserve;

- (e) Regulation, Spinning Reserve, Non-Spinning Reserve requirements must be satisfied by the combination of Regulation, Spinning Reserve and Non-Spinning Reserve bids;
- (f) Additional Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve capacity can be used to satisfy requirements for Replacement Reserve except that any Spinning and Non-Spinning Reserve capacity that 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 cannot be used to satisfy requirements for Replacement Reserve;
- (g) Total MW purchased from the Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve markets will not be changed by this Section 8.2.3.6; and
- (h) All quantities of Ancillary Services so procured must be non-negative.

8.2.4 Locational Quantities of Ancillary Services.

For each of the Ancillary Services, the ISO shall determine the required locational dispersion in accordance with ISO Controlled Grid reliability requirements. These standards shall be used as guidance only. The actual location of Ancillary Services on a daily and hourly basis shall depend on the locational spread of Demand within the ISO Control Area, the available transmission capacity, the locational mix of Generation, and historical patterns of transmission and Generation availability.

8.2.5 Black Start Units. The ISO will select Black Start capacity in locations where adequate transmission capacity can be made readily available (assuming no transmission damage) to connect the Black Start Generating Unit to the station service bus of a Generating Unit designated by the ISO. Black Start Units:

- (a) must be located in the ISO Control Area;
- (b) may be located anywhere in the ISO Control Area provided that the Black Start resource is capable of meeting the ISO performance requirements for starting and interconnection to the ISO Controlled Grid; but

(c) must be dispersed throughout the ISO Control Area.

8.2.5.1 Black Start Services.

(a) All Participating Generators with Black Start Generating Units must satisfy technical requirements specified by the ISO.

(b) The ISO shall from time to time undertake performance tests, with or without prior notification.

(c) The ISO shall have the sole right to determine when the operation of Black Start Generating Units is required to respond to conditions on the ISO Controlled Grid.

(d) If the ISO has intervened in the market for Energy and/or Ancillary Services pursuant to Section 7.4.4, the price paid by the ISO for Black Start services shall be sufficient to permit the relevant Participating Generator to recover its costs over the period that it is directed to operate by the ISO.

(e) If a Black Start Generating Unit fails to achieve a Black Start when called upon by the ISO, or fails to pass a performance test administered by the ISO, the Market Participant that has contracted to supply Black Start service from the Generating Unit shall re-pay to the ISO any reserve payment(s) that it has received since the administration of the last performance test or the last occasion upon which it successfully achieved a Black Start when called upon by the ISO, whichever is the shorter period.

8.3 Procurement of Ancillary Services, Certification and Testing Requirements for Providers of Ancillary Services, and Time-frame For Contracting for Ancillary Services.

8.3.1 Procurement of Ancillary Services.

Regulation, Operating Reserve, and Replacement Reserve necessary to meet ISO requirements not met by self-provision will be procured by the ISO as described in this ISO Tariff. As of the ISO Operations Date, the ISO will contract for long-term Voltage Support service with Owners of Reliability Must-Run Units under Reliability Must-Run Contracts. Black Start capability will initially be procured by the ISO through individual contracts with Scheduling Coordinators for Reliability Must-Run Units and other Generating Units which have Black Start capability. These requirements and standards apply to all Ancillary Services whether self-provided or procured by the ISO.

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.

8.4.1 Operating Characteristics Required to Provide Ancillary Services.

Each Generating Unit, System Unit, Load or System Resource which a Scheduling Coordinator wishes to schedule or bid to provide Ancillary Services must comply with the requirements for the specific Ancillary Service in regard to the following:

- (a) ramp rate increase and decrease (MW/minute);
- (b) power factor (leading and lagging) as required by Section 8.2.3.4;
- (c) maximum output (real and reactive), except that System Resources shall be required to comply only with the requirement for maximum real power;
- (d) minimum output (real and reactive), except that System Resources shall be required to comply only with the requirement for minimum real power;
- (e) AGC capability, control scheme, and range; and
- (f) minimum length of time the resource can be available to provide the relevant Ancillary Service.

The ISO will differentiate the operating characteristics according to the Ancillary Service being provided.

8.4.1.1 Regulation.

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

- (a) it must be capable of being controlled and monitored by the ISO Energy Management System (EMS) by means of the installation and use of a standard ISO direct communication and direct control system, a description of which and criteria for any temporary exemption from which, the ISO shall publish on the ISO internet "Home Page;"
- (b) it must be capable of achieving at least the ramp rates (increase and decrease in MW/minute) stated in its bid for the full amount of Regulation capacity offered;

- (c) the Regulation capacity offered must not exceed the maximum ramp rate (MW/minute) of that Unit times a value within a range from a minimum of ten minutes to a maximum of thirty minutes, which value shall be specified by the ISO and published on the ISO's internet "Home Page;"
- (d) the Generating Unit to ISO Control Center telemetry must in a manner meeting ISO standards include indications of whether the Generating Unit is on or off AGC at the Generating Unit terminal equipment;
- (e) the Generating Unit must be capable of the full range of movement within the amount of Regulation capability offered without manual Generating Unit operator intervention of any kind; and
- (f) each Participating Generator must ensure that the ISO EMS control and related SCADA equipment for its generating facility are operational throughout the time period during which Regulation is required to be provided.

8.4.1.2 Voltage Support.

A Generating Unit providing Voltage Support must be under the control of generator automatic voltage regulators throughout the time period during which Voltage Support is required to be provided. A Generating Unit may be required to operate underexcited (absorb reactive power) at periods of light system Demand to avoid potential high voltage conditions, or overexcited (produce reactive power) at periods of heavy system Demand to avoid potential low voltage conditions.

8.4.2 Ancillary Service Control Standards. The providers of ancillary services under this Tariff must comply with the following control standards:

- (a) Regulation. The ACE will be calculated by the ISO EMS. Control signals will be sent from the ISO EMS to raise or lower the output of Generating Units or System Resources providing Regulation when ACE exceeds the allowable ISO Control Area dead band for ACE;
- (b) Spinning and Non-Spinning Reserve. Each provider of Spinning Reserve or Non-Spinning Reserve must be capable of receiving a Dispatch instruction within one minute from the time the ISO Control Center elects to Dispatch the Spinning Reserve resource or Non-Spinning Reserve resource and

must ensure that its resource can be at the Dispatched operating level within ten minutes after issue of the Dispatch instruction;

(c) Replacement Reserve. Each provider of Replacement Reserve must be capable of receiving a Dispatch instruction within one minute from the time the ISO Control Center elects to Dispatch the Replacement Reserve resource and must ensure that its resource can be at the Dispatched operating level or condition within sixty minutes after issue of the Dispatch instruction;

(d) Voltage Support. Generating Units providing Voltage Support must have automatic voltage regulators which can correct the bus voltages to be within the prescribed voltage limits and within the machine capability in less than one minute; and

(e) Black Start. (i) Voice Communications: each supplier of Black Start capability must ensure that normal and emergency voice communications are available to permit effective Dispatch of the Black Start capability; (ii) ISO Confirmation: No load served by the Black Start Generating Unit or by any designated Generating Unit or by any transmission facility used for Black Start service may be restored until the ISO has confirmed that the need for such service has passed.

8.4.3 Ancillary Service Capability Standards. The providers of ancillary services under this Tariff must comply with the following capability standards

(a) Spinning and Non-Spinning Reserve Capability. Each Generating Unit or external import of a System Resource scheduled to provide Spinning Reserve and each resource providing Non-Spinning Reserve must be capable of converting the full capacity reserved to Energy production within ten minutes after the issue of the Dispatch instruction by the ISO, and of maintaining that output or scheduled interchange for at least two hours.

(b) Replacement Reserve. Each resource providing Replacement Reserve must be capable of supplying any level of output up to and including its full reserved capacity within sixty minutes after issue of Dispatch instructions by the ISO. Replacement Reserve may be supplied from resources already providing another Ancillary Service, such as Spinning Reserve, but only to the extent that the ability to provide the other Ancillary Service is not restricted in any way by the provision of Replacement Reserve.

The sum of Ancillary Service capacity supplied by the same resource cannot exceed the capacity of said resource.

(c) Black Start. Each Black Start Generating Unit must be able to start up with a dead primary and station service bus within ten minutes of issue of a Dispatch instruction by the ISO requiring a Black Start. Each Black Start Generating Unit must provide sufficient reactive capability to keep the energized transmission bus voltages within emergency voltage limits over the range of no-load to full load. Each Black Start Generating Unit must be capable of sustaining its output for a minimum period of 12 hours from the time when it first starts delivering Energy.

8.4.4 Ancillary Service Availability Standards. The providers of ancillary services under this Tariff must comply with the following availability standards.

(a) Spinning and Non-Spinning Reserve. Each Participating Generator shall ensure: (i) that its Generating Units scheduled to provide Spinning Reserve and Non-Spinning reserve are available for Dispatch throughout the Settlement Period for which they have been scheduled; and (ii) that its Generating Units scheduled to provide Spinning Reserve are responsive to frequency deviations throughout the Settlement Period for which they have been scheduled.

(b) Replacement Reserve. Each resource providing Replacement Reserve must be capable of sustaining the instructed output for at least two hours.

8.4.5 Communication Equipment.

Unless otherwise authorized by the ISO, all Scheduling Coordinators wishing to submit an Ancillary Service schedule or bid must have the capability to submit and receive information by direct computer link. In addition, they must be capable of receiving Dispatch instructions electronically and they must provide the ISO with a telephone number, or fax number through which Dispatch instructions for each Generating Unit, System Unit, Load and System Resource may be given if necessary. The ISO will determine which method of communication is appropriate; provided that the ISO will consult with the Scheduling Coordinator, if time permits, and will consider the method of communication then utilized by such Scheduling Coordinator; provided further, that the ISO shall make the final determination as to the

additional communication methods. Participating Generators, owners or operators of Loads and operators of System Units or System Resources whose resources are scheduled, bid in or under contract, shall ensure that there is a 24 hour personal point of contact with the ISO for the Generating Unit, System Unit, Load or System Resource. A Participating Generator or provider of Curtailable Demand wishing to offer any Ancillary Service must provide a direct ring down voice communications circuit (or a dedicated telephone line available 24 hours a day every day of the year) between the control room operator for the Generating Unit or Curtailable Demand providing the Ancillary Service and the ISO Control Center. Each Participating Generator must also provide an alternate method of voice communications with the ISO from the control room in addition to the direct communication link required above. Operators of System Resources from which dynamic schedules or bids are submitted to the ISO shall provide communications links meeting ISO standards for dynamic imports from System Resources. Participating Generators and operators of System Units providing Regulation shall also provide communication links meeting ISO standards for direct digital control. Operators of System Resources providing Regulation shall provide communications links meeting ISO standards for external imports of Regulation. If any communication system becomes unavailable, the relevant Participating Generators, operators of System Units, Loads and System Resources and the ISO shall take immediate action to identify the cause of the interruption and to restore the communication system. A Scheduling Coordinator that has scheduled or bid in or contracted for Ancillary Services shall ensure that the Generating Unit, System Unit, Load or System Resource concerned is able to receive and implement Dispatch Instructions.

8.4.6 Metering Infrastructure.

All Participating Generators, owners or operators of Loads and operators of System Units or System Resources which a Scheduling Coordinator wishes to schedule or bid to provide Ancillary Services shall have the metering infrastructure for the Generating Units, System Units, Loads or System Resources concerned which complies with requirements to be established by the ISO relating to:

- (a) meter type;
- (b) meter location;

- (c) meter reading responsibility;
- (d) meter capability in regard to AGC response; and
- (e) any other aspect of metering infrastructure required by the ISO under this ISO Tariff.

8.4.6.1 Additional Requirements for Black Start Units.

A Participating Generator who wishes to offer Black Start must ensure that the requirements set out in Appendix D to this ISO Tariff are met in relation to the Generating Units from which Black Start will be offered.

8.4.7 Methodology For Procurement of Ancillary Services Upon Commencement of ISO Operations.

8.4.7.1 Usage Charge in Ancillary Service Bid Evaluation.

Due to the design of the ISO's scheduling software, the ISO will not take into account Usage Charges in the evaluation of Ancillary Services bids or in price determination and, in the event of Congestion in the Day-Ahead Market or Hour-Ahead Market, Ancillary Services will be procured and priced on a Zonal basis.

8.4.7.2 Market-Based Prices.

Public utilities under the FPA must submit bids for Ancillary Services capped at FERC authorized cost-based rates unless and until FERC authorizes different pricing. Public utilities under the FPA shall seek FERC Ancillary Services rate approval on bases consistent with the ISO time-frame for contracting for each Ancillary Service (hourly rate for some Ancillary Services, annual rate or otherwise for other Ancillary Services) so that cost-based bids and market-based bids for each service shall be on comparable terms. All other entities may use market-based rates not subject to any restrictions apart from those found in this ISO Tariff. Public utilities under the FPA which have not been approved to bid at market-based rates, will not be paid above their cost-based bid for the Ancillary Service concerned even if the relevant Market Clearing Price is higher.

8.4.7.3 Bidding and Self-Provision of Ancillary Services.

The ISO will procure Ancillary Services in accordance with this ISO Tariff, and the applicable ISO Protocols.

8.4.7.3.1 Content of Ancillary Services Schedules and Bids.

Scheduling Coordinators may bid or self-provide Ancillary Services or specify Inter-Scheduling Coordinator Ancillary Service Trades from resources located within the ISO Control Area. Ancillary Services in the Day-Ahead Market and the Hour-Ahead Market are comprised of the following: Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve. Each Generating Unit (including Physical Scheduling Plants), System Unit, Curtailable Demand or System Resource for which a Scheduling Coordinator wishes to submit Ancillary Services Schedules and bids must meet the requirements set forth in this ISO Tariff. The same resource capacity may be offered into more than one ISO Ancillary Service auction at the same time (the sequential evaluation of such multiple offers between Ancillary Services markets to eliminate double counting of capacity is described in the Section 8.5.5). In each category of Ancillary Service, the reference to "Revised" types of Schedules indicates a submittal which is part of a Revised Day-Ahead Schedule. Each of the following data sections can be submitted up to seven (7) days in advance. Ramp rates submitted as detailed below will be only used by the ISO for procuring capacity associated with the specific Ancillary Services. The ISO will issue real-time Dispatch Instructions for the Energy associated with the awarded capacity based upon the applicable operational ramp rate submitted with the single Energy Bid curve in accordance with Section 30.4.6. There is no provision for external exports with regard to Ancillary Services bids. The functionality necessary to accept such bids does not exist in the ISO scheduling software.

8.4.7.3.2 Scheduling Coordinators may bid or self-provide external imports of Spinning Reserve, Non-Spinning Reserve or Replacement Reserve from System Resources located outside the ISO Control Area including dynamically scheduled System Resources, where technically feasible and consistent with WECC criteria; and provided that such Scheduling Coordinators have certified to the ISO their ability to deliver the service to the point of interchange with the ISO Control Area (including with respect to their

ability to make changes, or cause such changes to be made, to interchange schedules during any interval of a Settlement Period at the discretion of the ISO).

8.4.7.3.3 Scheduling Coordinators may bid or self-provide external imports of Regulation from System Resources located outside the ISO Control Area, where technically feasible and consistent with WECC criteria by dynamic scheduling; provided that the operator of the Control Area in which the System Resources are located has entered into an agreement with the ISO for interconnected Control Area operations; and provided that such Scheduling Coordinator and the operator of the Control Area in which the resources are located have been certified by the ISO as to their ability to dynamically adjust interchange schedules based on control signals issued by the ISO anytime during a Settlement Period at the discretion of the ISO. Such certification shall include a demonstration of their ability to support the dynamic interchange of Regulation service based on ISO control signals received on dedicated communications links (either directly or through EMS computers) for ISO computer control and telemetry to provide this function in accordance with ISO standards and procedures posted on the ISO Home Page.

8.4.7.3.4 Scheduling Coordinators may utilize transmission service under Existing Contracts to self-provide Regulation (consistent with this ISO Tariff), from resources located outside the ISO Control Area, where technically feasible, consistent with WECC standards.

8.4.7.3.5 Scheduling Coordinators' bidding or self-provision of Ancillary Services according to this Section 8.4.7.3 shall be consistent with the ISO Protocols.

8.4.7.3.6 Due to the design of the ISO's scheduling system, any specific resource can bid to supply a specific Ancillary Service or can self-provide such Ancillary Service but cannot do both in the same Settlement Period.

8.5 The Bidding Process.

The ISO shall operate a competitive Day-Ahead and Hour-Ahead Market to procure Ancillary Services. It shall purchase Ancillary Services capacity at least cost to End-Use Customers consistent with maintaining System Reliability. Any Scheduling Coordinator representing Generating Units, System Units, Loads or external imports of System Resources may bid into the ISO's Ancillary Services market provided that it is

in possession of a current certificate for the Generating Units, System Units, external imports of System Resources or Loads concerned.

8.5.1 Provision of System Information to Scheduling Coordinators.

By 6:00 p.m. two days prior to the Trading Day, the ISO shall make available to Scheduling Coordinators general system information including those items of information set forth in Section 6.9.1. This information shall be provided at the same time as the ISO provides general system information to all Scheduling Coordinators wishing to schedule power on the ISO Controlled Grid.

8.5.2 Time Frame for Submitting And Evaluating Bids.

8.5.2.1 Day-Ahead Auction.

Bids for the ISO's Day-Ahead Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve service market must be received by 10:00 am on the day prior to the Trading Day. The bids shall include information for each of the twenty-four (24) Settlement Periods of the Trading Day. Failure to provide the information within the stated time frame shall result in the bids being declared invalid by the ISO.

8.5.2.2 Hour-Ahead Auction. The ISO will require Scheduling Coordinators to honor their Day-Ahead Ancillary Services schedules and/or bids when submitting their Hour-Ahead Ancillary Services schedules and/or bids. Bids for the ISO's Hour-Ahead Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve service market for each Settlement Period must be received at least two hours prior to the commencement of that Settlement Period. The bids shall include information for only the relevant Settlement Period. Failure to provide the information within the stated time frame shall result in the bids being declared invalid by the ISO. Scheduling Coordinators wishing to buy back in the Hour-Ahead Market Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity sold to the ISO in the Day-Ahead Market pursuant to Section 8.7 must do so by submitting a revised bid in the Hour-Ahead Market for the Ancillary Service and resource concerned.

8.5.3 Information to Be Submitted By Bidders.

8.5.3.1 Information for Use in Day-Ahead Market and Hour-Ahead Market.

Bids shall be submitted by Scheduling Coordinators acting on behalf of Participating Generators, and owners or operators of Loads. Bids must be in the format specified by the ISO and include the bid information for each service described in Sections 8.5.6 to 8.5.10 and such other information as the ISO may determine it requires to evaluate bids as published from time to time in this ISO Tariff or ISO Protocols. The ISO will verify and respond to submitted bid data in accordance with Appendix E and the ISO Protocols. Bidders may submit new bids on a daily basis (or hourly basis for the Hour-Ahead Market).

8.5.3.2 Information for Use in Real-Time Dispatch of Ancillary Services.

Scheduling Coordinators with Ancillary Services awards must submit a single Energy Bid curve in the Real Time Market to correspond to any awarded capacity for the relevant resources Scheduling Coordinators must submit Energy Bids for resources providing Spinning, Non-Spinning, or Replacement Reserves.

8.5.4 Bid Evaluation Rules.

Bid evaluation shall be based on the following principles:

- (a) the ISO shall not differentiate between bidders other than through price and capability to provide the service, and the required locational mix of services;
- (b) to minimize the costs to users of the ISO Controlled Grid, the ISO shall select the bidders with lowest bids for capacity which meet its technical requirements, including location and operating capability;
- (c) for the Day-Ahead Market, the Day-Ahead bids shall be evaluated independently for each of the 24 Settlement Periods of the following Trading Day;
- (d) for the Hour-Ahead Market, the ISO shall evaluate bids in the two hours preceding the hour of operation;

- (e) the ISO will procure sufficient Ancillary Services in the Day-Ahead Market to meet its forecasted requirements, as known at the close of the Day-Ahead Market, except that the ISO may elect to procure a portion of such requirements in the Hour-Ahead Markets if the ISO first provides notice to Scheduling Coordinators of such action, including the approximate hourly megawatt amounts of each Ancillary Service that it intends to procure in the Hour-Ahead Markets;
- (f) the ISO will (to the extent available) procure sufficient Ancillary Services to meet its requirements;
and
- (g) the ISO will evaluate and price only those Ancillary Services bids received.

8.5.5 Evaluation of Ancillary Services Bids.

When Scheduling Coordinators bid into the Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve markets, they may bid the same capacity into as many of these markets as desired at the same time by providing the appropriate bid information to the ISO. The ISO shall evaluate bids in the markets for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve sequentially and separately in the following order: Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve. Any capacity accepted by the ISO in one of these markets shall not be passed on to another market, except that capacity accepted in the Regulation market that represents the downward range of movement accepted by the ISO may be passed on to another market; any losing bids in one market may be passed onto another market, if the Scheduling Coordinator so indicates to the ISO. A Scheduling Coordinator may specify capacity bid into only the markets it desires. A Scheduling Coordinator shall also have the ability to specify different capacity prices and different Energy prices for the Spinning Reserve, Non-Spinning Reserve, Replacement Reserve and Regulation markets. The bid information, bid evaluation and price determination rules set forth below shall be used in the Day-Ahead, Hour-Ahead and real-time procurement of Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve.

A Scheduling Coordinator providing one or more Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve services may not change the identification of the Generating Units or

Loads offered in the Day-Ahead Market, the Hour-Ahead Market or in real time for such services unless specifically approved by the ISO (except with respect to System Units, if any, in which case Scheduling Coordinators are required to identify and disclose the resource specific information for all Generating Units and Curtailable Demands constituting the System Unit scheduled or bid into the ISO's Day-Ahead Market and Hour-Ahead Market as required in SP 3.3.2(e) in Appendix Y).

8.5.5.1 Ancillary Service Bid Evaluation and Pricing Terminology.

Unless otherwise specifically described herein, the following terminology will apply:

$CapRes_{ijt}$	=	the Ancillary Service reserve reservation bid price (in \$/MW).
Cap_{ijtmax}	=	the maximum amount of reserve that can be scheduled by the ISO with respect to a Scheduling Coordinator's bid of that resource to supply Ancillary Services (in MW).
Cap_{ij}	=	that portion of an Ancillary Services bid (in MW), identified in the ISO's evaluation process, that may be used to meet the ISO's Requirement for a particular Ancillary Service ($Cap_{ijt} < Cap_{ijtmax}$)
Requirement	=	the total amount of reserve that must be scheduled for a particular Ancillary Service required by the ISO in a Settlement Period (in MW).
i, j, t	=	Generating Unit i , Scheduling Coordinator j , Settlement Period t .

8.5.6 The Regulation Auction.

Bid Information. Each Scheduling Coordinator j desiring to participate in the ISO's Regulation auction will submit the following information for each relevant Generating Unit or System Unit i for each Settlement Period t of the relevant Trading Day:

- (a) bidder name/Identification Code and Scheduling Coordinator's ID code;
- (b) resource identification (name and Location Code);

- (c) the date for which the bid applies;
- (d) maximum operating level (MW);
- (e) minimum operating level (MW);
- (f) ramp rate (MW/Min) $Ramp_{ijt}$;
- (g) the upward and downward range of generating capacity over which Generating Unit or System Unit i from Scheduling Coordinator j is willing to provide Regulation for Settlement Period t ($Cap_{ijt}max$ (MW) where $Cap_{ijt}max \leq Period_{minutes} * Ramp_{ijt}$. $Period_{minutes}$ is established by the ISO, by giving Scheduling Coordinators twenty-four (24) hours advance notice, within a range from a minimum of 10 minutes to a maximum of 30 minutes. Bidders shall offer upward and downward range for Regulation service;
- (h) the bid price of the capacity reservation, stated separately for Regulation Up and Regulation Down ($CapRes_{ijt}$ (\$/MW));
- (i) type of schedule: Regulation Ancillary Service (ANC_SRVC) or Revised Regulation Ancillary Service (REVISED_ANC_SRVC);
- (j) type of market (Day-Ahead or Hour-Ahead) and Trading Day;
- (k) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule; and
- (l) upward and downward range of Generating Unit or System Unit capacity over which the Generating Unit or System Unit is offering to provide Regulation.

Each Scheduling Coordinator desiring to participate in the ISO's Regulation auction will submit the following information for each relevant external import for each Settlement Period of the relevant Trading Day:

- (a) bidder name/Identification Code and Scheduling Coordinator's ID code;
- (b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;
- (c) Scheduling Point (the name);

- (d) interchange ID code(the name of the selling entity, buying entity and a numeric identifier);
- (e) external Control Area ID;
- (f) Schedule ID (NERC ID number) and complete WECC tag;
- (g) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;
- (h) the contract reference number, if applicable,
- (i) maximum operating level (MW);
- (j) minimum operating level (MW);
- (k) ramp rate (MW/Min) $Ramp_{ijt}$;
- (l) the upward and downward range of generating capacity over which System Resource i from Scheduling Coordinator j is willing to provide Regulation for Settlement Period t ($Cap_{ijt,max}$ (MW)) where $Cap_{ijt,max} \leq Period_{minutes} * Ramp_{ijt}$. $Period_{minutes}$ is established by the ISO, by giving Scheduling Coordinators twenty-four (24) hours advance notice, within a range from a minimum of 10 minutes to a maximum of 30 minutes. Bidders shall offer upward and downward range for Regulation service;
- (m) the bid price of the capacity reservation, stated separately for Regulation Up and Regulation Down ($CapRes_{ijt}$ (\$/MW)); and
- (n) type of schedule: (Regulation Ancillary Service).

Bid Evaluation. Based on the quantity and location of the system requirements, the ISO shall select Generating Units, System Units, and System Resources with the bids, which minimize the sum of the total bids of the Generating Units, System Units, and System Resources selected for Regulation Up or Regulation Down, subject to two constraints:

- (a) the sum of the selected bid capacities must be greater than or equal to the required Regulation capacity; and

- (b) each Generating Unit's, System Unit's, or System Resource's bid capacity must be less than or equal to that Generating Unit's, System Unit's, or System Resource's ramp rate times $\text{Period}_{\text{minutes}}$ where $\text{Period}_{\text{minute}}$ is established by the ISO, by giving Scheduling Coordinators twenty-four (24) hours advance notice, within a range from a minimum of 10 minutes to a maximum of 30 minutes.

The total bid for each Generating Unit, System Unit, or System Resource is calculated by multiplying the capacity reservation bid price by the bid capacity.

Thus, subject to any locational requirements, the ISO will accept winning Regulation bids in accordance with the following criteria:

$$\text{Min} \sum_{i,j} \text{TotalBid}_{ijt}$$

Subject to

$$\sum_{i,j} \text{Cap}_{ijt} \geq \text{Requirement}_t \text{ and } \text{Cap}_{ijt} \leq \text{Cap}_{ij\text{max}}$$

Where

$$\text{TotalBid}_{ijt} = \text{CapRes}_{ijt} * \text{Cap}_{ijt}$$

Requirement_t = Amount of upward and downward movement capacity required

Price Determination. The price payable to Scheduling Coordinators for Regulation Capacity made available for upward and downward movement in accordance with the ISO's Final Day-Ahead Schedules shall, for each Generating Unit, System Unit, and System Resource concerned, be the Zonal Market Clearing Price as follows:

$$\text{PAGC}_x = \text{MCP}_{xt}$$

Where:

The Zonal Market Clearing Price (MCP_{xt}) is the highest priced winning Regulation capacity bid in Zone X based on the capacity reservation bid price, i.e.

$$MCP_{xt} = \text{Max} (CapRes_{ijt}) \text{ in Zone } x \text{ for Settlement Period } t$$

In the absence of Inter-Zonal Congestion, the Zonal Market Clearing Prices will be equal.

The ISO's auction does not compensate the Scheduling Coordinator for the minimum Energy output of Generating Units, System Units, or System Resources bidding to provide Regulation. Therefore, disposition of any minimum Energy associated with Regulation selected in the ISO's Ancillary Services markets is the responsibility of the Scheduling Coordinator selling the Regulation.

The price payable to Scheduling Coordinators for Regulation capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 8.7 shall be the bid price of the Regulation Capacity reserved ($CapRes_{ijt}$ (\$/MW)).

8.5.7 The Spinning Reserve Auction.

Bid Information. If the bid is for the provision of Spinning Reserve from a Generating Unit or System Unit, each Scheduling Coordinator j must submit the following information for each Generating Unit or System Unit i for each Settlement Period t of the following Trading Day:

- (a) bidder name/Identification Code;
- (b) resource identification (name and Location Code);
- (c) the date for which the bid applies;
- (d) maximum operating level (MW);
- (e) minimum operating level (MW);
- (f) ramp rate (MW/min);

- (g) MW additional capability synchronized to the system, immediately responsive to system frequency, and available within 10 minutes (Cap_{ijtmax}) for Generating Unit i, or System Unit I, from Scheduling Coordinator j, for Settlement Period t;
- (h) bid price of capacity reserved ($CapRes_{ijt}$ (\$/MW));
- (i) an indication whether the capacity reserved would be 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;
- (j) type of schedule: Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);
- (k) type of market (Day-Ahead or Hour-Ahead) and Trading Day;
- (l) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule; and
- (m) Spinning Reserve capacity (MW).

If the bid is for the provision of Spinning Reserve from an external import of a System Resource, each Scheduling Coordinator j must submit the following information for each external import of a System Resource i for each Settlement Period t of the following Trading Day:

- (a) bidder name/Identification Code;
- (b) the date for which the bid applies;
- (c) ramp rate if applicable (MW/Min);
- (d) MW additional capability synchronized to the system, immediately responsive to system frequency and available at the point of interchange with the ISO Control Area, within 10 minutes (Cap_{ijtmax}) of the ISO calling for the external import of System Resource i, from Scheduling Coordinator j, for Settlement Period t;
- (e) bid price of capacity reserved ($CapRes_{ijt}$ (\$/MW));

- (f) an indication whether the capacity reserved would be 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; and, for a dynamic import of a System Resource, the following additional information:
- (g) type of market (Day-Ahead or Hour-Ahead) and Trading Day;
- (h) Scheduling Point (the name);
- (i) interchange ID code(the name of the selling entity, buying entity and a numeric identifier);
- (j) external Control Area ID;
- (k) Schedule ID (NERC ID number) and complete WECC tag;
- (l) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;
- (m) the contract reference number, if applicable;
- (n) type of schedule: Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);
- (o) export flag, a "YES" indicates an external export and a "NO" indicates an external import; and
- (p) Spinning Reserve capacity (MW).

Bid Evaluation. Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units and external imports of System Resources with the bids which minimize the sum of the total bids of the Generating Units, System Units and external imports of System Resources selected subject to two constraints:

- (a) the sum of the selected bid capacities must be greater than or equal to the required Spinning Reserve capacity; and
- (b) each Generating Unit's, System Unit's or external import's bid capacity must be less than or equal to that Generating Unit's, System Unit's or external import's ramp rate times 10 minutes.

The total bid for each Generating Unit, System Unit or external import of a System Resource is calculated by multiplying the capacity reservation bid price by the bid capacity. Thus, subject to any locational requirements, the ISO will select the winning Spinning Reserve bids in accordance with the following criteria:

$$\text{Min} \sum_{i,j} \text{Totalbid}_{ijt}$$

Subject to

$$\sum_{i,j} \text{Cap}_{ijt} \geq \text{Requirement}_t$$

and $\text{Cap}_{ijt} \leq \text{Cap}_{ijtmax}$

Where

$$\text{TotalBid}_{ijt} = \text{Cap}_{ijt} * \text{CapRes}_{ijt}$$

Requirement_t = the amount of Spinning Reserve capacity required

Price Determination. The price payable to Scheduling Coordinators for Spinning Reserve Capacity made available in accordance with the ISO's Final Day-Ahead Schedules shall, for each Generating Unit or external import of a System Resource concerned be the Zonal Market Clearing Price for Spinning Reserve calculated as follows:

$$P_{sp_{xt}} = MCP_{xt}$$

Where the Zonal Market Clearing Price (MCP_{xt}) for Spinning Reserve is the highest priced winning Spinning Reserve capacity bid in Zone X based on the capacity reservation bid price, i.e.:

$$MCP_{xt} = \text{Max}(\text{CapRes}_{ijt}) \text{ in Zone } x \text{ for Settlement Period } t$$

In the absence of Inter-Zonal Congestion, the Zonal Market Clearing Prices will be equal.

The ISO's auction does not compensate a Scheduling Coordinator for the minimum Energy output of Generating Units, System Units or System Resources bidding to provide Spinning Reserve.

Therefore, any minimum Energy output associated with Spinning Reserve selected in the ISO's auction is the responsibility of the Scheduling Coordinator selling the Spinning Reserve.

The price payable to Scheduling Coordinators for Spinning Reserve Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 8.7 shall be the bid price of the Spinning Reserve capacity reserved ($CapRes_{ijt}(\$/MW)$).

8.5.8 The Non-Spinning Reserve Auction.

Bid information. If the bid is for the provision of Non-Spinning Reserve from a Generating Unit or System Unit, each Scheduling Coordinator j must submit the following information for each Generating Unit or System Unit i for each Settlement Period t of the following Trading Day:

- (a) bidder name/Identification Code;
- (b) Generating Unit or System Unit identification (name and Location Code);
- (c) the date for which the bid applies;
- (d) maximum operating level (MW);
- (e) minimum operating level (MW);
- (f) ramp rate (MW/Min);
- (g) the MW capability available within 10 minutes (Cap_{ijtmax});
- (h) the bid price of the capacity reserved ($CapRes_{ijt}(\$/MW)$);
- (i) time to synchronization following notification (min);
- (j) an indication whether the capacity reserved would be 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;

- (k) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Non-Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);
- (l) type of market (Day-Ahead or Hour-Ahead) and Trading Day; and
- (m) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule.

If the bid is for the provision of Non-Spinning Reserve from an external import of a System Resource, each Scheduling Coordinator j must submit the following information for each external import of a System Resource i for each Settlement Period t of the following Trading Day:

- (a) bidder name/Identification Code;
- (b) the date for which the bid applies;
- (c) ramp rate if applicable (MW/Min);
- (d) the MW capability available at the point of interchange with the ISO Control Area, within 10 minutes (Cap_{ijtmax}) of the ISO calling for the external import of System Resource i , from Scheduling Coordinator j , for Settlement Period t ;
- (e) the bid price of the capacity reserved ($CapRes_{ijt}(\$/MW)$);
- (f) an indication whether the capacity reserved would be 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; and, for a dynamic import of a System Resource, the following additional information:
 - (g) type of market (Day-Ahead or Hour-Ahead) and Trading Day;
 - (h) Scheduling Point (the name);
 - (i) interchange ID code (the name of the selling entity, buying entity and a numeric identifier);
 - (j) external Control Area ID;
 - (k) Schedule ID (NERC ID number) and complete WECC tag;

- (l) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;
- (m) the contract reference number, if applicable;
- (n) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Non-Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);
- (o) export flag, a "YES" indicates an external export and a "NO" indicates an external import; and
- (p) Non-Spinning Reserve capacity (MW).

If the bid is for the provision of Non-Spinning Reserve from a Load located within the ISO Control Area, each Scheduling Coordinator j must submit the following information for each Load i for each Settlement Period t of the following Trading Day:

- (a) bidder name/Identification Code;
- (b) Load identification name and Location Code;
- (c) the date for which the bid applies;
- (d) Demand reduction available within 10 minutes ($Cap_{ijt}max$);
- (e) to interruption following notification (min);
- (f) maximum allowable curtailment duration (hr);
- (g) the bid price of the capacity reserved ($CapRes_{ijt}(\$/MW)$);
- (h) an indication whether the capacity reserved would be available for Demand reduction only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency;
- (i) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Non-Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);
- (j) type of market (Day-Ahead and Hour-Ahead) and Trading Day; and
- (k) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule.

Bid Evaluation. Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units, Loads or external imports of System Resources with the bids which minimize the sum of the total bids of the Generating Units, System Units, Loads or external imports of System Resources selected subject to two constraints:

- (a) the sum of the selected bid capacities must be greater than or equal to the required Non-Spinning Reserve capacity; and
- (b) each Generating Unit's, System Unit's, Load's or external import's bid capacity must be less than or equal to that Generating Unit's, System Unit's, Load's or external import's ramp rate (or time to interruption in the case of a Load offering Demand reduction) times the difference between 10 minutes and the time to synchronize in the case of a Generating Unit or System Unit or to interruption in the case of a Load. The total bid for each Generating Unit, System Unit, Load or external import of a System Resource is calculated by multiplying the capacity reservation bid by the bid capacity.

Thus subject to any locational requirements, the ISO will accept the winning Non-Spinning Reserve bids in accordance with the following criteria:

$$\text{Min} \sum_{i,j} \text{Totalbid}_{ijt}$$

Subject to

$$\sum_{i,j} \text{Cap}_{ijt} \geq \text{Requirement}_t$$

$$\text{Cap}_{ijt} \leq \text{Cap}_{ijtmax}$$

Where

$$\text{TotalBid}_{ijt} = \text{Cap}_{ijt} * \text{CapRes}_{ijt}$$

Requirement_t = the amount of Non-Spinning Reserve capacity required

Price Determination. The price payable to Scheduling Coordinators for Non-Spinning Reserve Capacity made available in accordance with the ISO's Final Day-Ahead Schedules shall for each

Generating Unit, System Unit, Load or external import of a System Resource concerned be the Zonal Market Clearing Price for Non-Spinning Reserve calculated as follows:

$$P_{nonsp_{xt}} = MCP_{xt}$$

Where the Zonal Market Clearing Price (MCP_{xt}) for Non-Spinning Reserve is the highest priced winning Non-Spinning Reserve bid in Zone X based on the capacity reservation bid price, i.e.:

$$MCP_{xt} = \text{Max}(CapRes_{ijt}) \text{ in Zone } x \text{ for Settlement Period } t.$$

In the absence of Inter-Zonal Congestion, the Zonal Market Clearing Prices will be equal.

The price payable to Scheduling Coordinators for Non-Spinning Reserve Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 8.7 shall be the bid price of the Non-Spinning Capacity reserved ($CapRes_{ijt}(\$/MW)$).

8.5.8A The Replacement Reserve Auction.

Bid Information. If the bid is for the provision of Replacement Reserve from a Generating Unit or System Unit each Scheduling Coordinator j must submit the following information for each Generating Unit or System Unit i for each Settlement Period t of the following Trading Day:

- (a) bidder name/Identification Code;
- (b) Generating Unit or System Unit identification (name and Location Code);
- (c) the date for which the bid applies;
- (d) maximum operating level (MW);
- (e) minimum operating level (MW);
- (f) ramp rate (MW/Min);
- (g) the MW capacity available within 60 minutes (Cap_{ijtmax});
- (h) the bid price of the capacity reserved ($CapRes_{ijt}(\$/MW)$);

- (i) time to synchronize following notification (min).
- (j) type of schedule: Replacement Reserve Ancillary Service (ANC_SRVC) or Revised Replacement Reserve Ancillary Service (REVISED_ANC_SRVC);
- (k) type of market (Day-Ahead or Hour-Ahead) and Trading Day; and
- (l) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule.

If the bid is for the provision of Replacement Reserve from an external import of a System Resource, each Scheduling Coordinator j must submit the following information for each external import of a System Resource i for each Settlement Period t of the following Trading Day:

- (a) bidder name/Identification Code;
- (b) the date for which the bid applies;
- (c) ramp rate applicable (MW/Min);
- (d) the MW capability available at the point of interchange with the ISO Control Area, within 60 minutes (Cap_{ijtmax}) of the ISO calling for the external import of System Resource i, from Scheduling Coordinator j, for Settlement Period t;
- (e) bid price of capacity reserved ($CapRes_{ijt}(\$/MW)$); and, for a dynamic import of a System Resource, the following additional information:
 - (h) type of market (Day-Ahead or Hour-Ahead) and Trading Day;
 - (i) Scheduling Point (the name);
 - (j) interchange ID code (the name of the selling entity, buying entity and a numeric identifier);
 - (k) external Control Area ID;
 - (l) Schedule ID (NERC ID number) and complete WECC tag;
- (m) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;
- (n) the contract reference number, if applicable;

- (o) type of schedule: Replacement Reserve Ancillary Service (ANC_SRVC) or Revised Replacement Reserve Ancillary Service (REVISED_ANC_SRVC);
- (p) time to synchronize following notification (less than sixty (60) minutes mandatory); and
- (q) Replacement Reserve capacity (MW).

If the bid is for the provision of Replacement Reserve from a Load located within the ISO Control Area, each Scheduling Coordinator j must submit the following information for each Load i for each Settlement Period t of the following Trading Day:

- (a) bidder name/Identification Code;
- (b) Load identification (name and Location Code);
- (c) the date for which the bid applies;
- (d) the Demand reduction available within 60 minutes (Cap_{ijt} (MW));
- (e) time to interruption following notification (min);
- (f) maximum allowable curtailment duration (hr);
- (g) the bid price of the capacity reserved ($CapRes_{ijt}$ (\$/MW));
- (h) type of schedule: Replacement Reserve Ancillary Service (ANC_SRVC) or Revised Replacement Reserve Ancillary Service (REVISED_ANC_SRVC);
- (i) type of market (Day-Ahead or Hour-Ahead) and Trading Day;
- (j) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule; and
- (k) Curtailable Demand reduction rate (MW/minute).

Bid Evaluation. Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units, Loads or external imports of System Resources with the bids which minimize the sum of the total bids of the Generating Units, System Units, Loads or external imports of System Resources selected subject to two constraints:

- (a) the sum of the selected bid capacities must be greater than or equal to the required Replacement Reserve capacity; and
- (b) each Generating Unit's, System Unit's, Load's or external import's bid capacity must be less than or equal to that Generating Unit's, System Unit's, Load's or external import's ramp rate (or time to interruption in the case of a Load offering Demand reduction) times the difference between 60 minutes and the time to synchronize in the case of Generating Unit or System Unit, or to interruption in the case of Load.

The total bid for each Generating Unit, System Unit, Load or external import of System Resource is calculated by multiplying the capacity reservation bid price by the bid capacity.

Thus, subject to any locational requirements, the ISO will select the winning Replacement Reserve bids in accordance with the following criteria:

$$\text{Min} \sum_{i,j} \text{Totalbid}_{ijt}$$

Subject to

$$\sum_{i,j} \text{Cap}_{ijt} \geq \text{Requirement}_t$$

$$\text{Cap}_{ijt} \leq \text{Cap}_{ijtmax}$$

Where

$$\text{TotalBid}_{ijt} = \text{Cap}_{ijt} * \text{CapRes}_{ijt}$$

Requirement_t = the amount of Replacement Reserve capacity required

Price Determination. The price payable to Scheduling Coordinators for Replacement Reserve Capacity made available in accordance with the ISO's Final Day-Ahead Schedules shall, for each Generating Unit, System Unit, Load or external import of a System Resource concerned, be the Zonal Market Clearing Price for Replacement Reserve calculated as follows:

$$P_{\text{RepRes}_{xt}} = \text{MCP}_{xt}$$

Where the Zonal Market Clearing Price (MCP_{xt}) for Replacement Reserve is the highest priced winning Replacement Reserve bid in Zone X based on the capacity reservation bid price, i.e.:

$$MCP_{xt} = \text{Max}(CapRes_{ijt}) \text{ in Zone } x \text{ for Settlement Period } t.$$

In the absence of Inter-Zonal Congestion, the Zonal Market Clearing Prices will be equal.

The price payable to Scheduling Coordinators for Replacement Reserve Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services schedules issued in accordance with Section 8.7 shall be the bid price of the Replacement Reserve capacity reserved ($CapRes_{ijt}(\$/MW)$).

8.5.9 Voltage Support.

As of the ISO Operations Date, the ISO will contract for Voltage Support service with the owners of Reliability Must-Run Units. Payments for public utilities under the FPA shall be capped at the FERC authorized cost-based rates unless and until FERC authorizes different pricing. The ISO shall pay owners of Reliability Must-Run Units for long-term Voltage Support through their Scheduling Coordinators.

In addition, any Participating Generator who is producing Energy shall, upon the ISO's specific request, provide reactive energy output outside the Participating Generator's Voltage Support obligation defined in Section 8.2.3.4.

The ISO shall select Participating Generator's Generating Units which have been certified for Voltage Support to provide this additional Voltage Support. Subject to any locational requirements, the ISO shall select the least costly Generating Units from a computerized merit order stack to back down to produce additional Voltage Support in each location where Voltage Support is needed.

The ISO shall pay to the Scheduling Coordinator for that Participating Generator the opportunity cost of reducing Energy output to enable reactive energy production. This opportunity cost shall be:

$\text{Max}\{0, \text{Zonal Settlement Interval Ex Post Price} - \text{Generating Unit bid price}\} \times \text{reduction in Energy output (MW)}$.

If necessary, the ISO shall develop a regulatory cost-based determination of marginal operating cost to be used in place of the Generating Unit bid price.

8.5.10 Black Start Capability and Energy Output.

As of the ISO Operations Date, the ISO will contract for Black Start capability and Energy with owners of Reliability Must-Run Units and Black Start Generators. Public utilities under the FPA will be paid rates capped at the FERC authorized cost base rates unless and until FERC authorizes different pricing.

The ISO shall pay owners of Reliability Must-Run Units for Black Start Energy output through their Scheduling Coordinators. The ISO shall pay Black Start Generators for Black Start Energy output directly.

8.6 Obligations for and Self-Provision of Ancillary Services.

8.6.1 Ancillary Service Obligations.

Each Scheduling Coordinator shall be assigned a share of the total Regulation, Spinning Reserve, Non-Spinning and Replacement Reserve requirements by the ISO. Any references in this Tariff to the Ancillary Service "Regulation" shall be read as referring to "Regulation Up" or "Regulation Down". The share assigned to each Scheduling Coordinator is described in Section 8.6 and in Section 8.12 as that Scheduling Coordinator's obligation. Each Scheduling Coordinator's Regulation obligation in each Zone shall be pro rata based upon the same proportion as the Scheduling Coordinator's metered hourly Demand (excluding exports) bears to the total metered Demand (excluding exports) served in each hour in that Zone. Each Scheduling Coordinator's Operating Reserve obligation in each Zone shall be pro rata based upon the same proportion as the ratio of the product of its percentage obligation based on metered output and the sum of its metered Demand and firm exports bears to the total of such products for all Scheduling Coordinators in the Zone. The Scheduling Coordinator's percentage obligation based on metered output shall be calculated as the sum of 5% of its real-time Demand (except the Demand covered by firm purchases from outside the ISO Control Area) met by Generation from hydroelectric resources plus 7% of its Demand (except the Demand covered by firm purchases from outside the ISO Control Area) met by Generation from non-hydroelectric resources in that Zone, plus 100% of any Interruptible Imports and on-demand obligations which it schedules. Each Scheduling Coordinator's

Replacement Reserve obligation in each Zone is calculated as described in Section 8.12.3A. Scheduling Coordinator obligations for each Ancillary Service will be calculated based on the requirement for each Ancillary Service as the ISO determines prior to the adjustment set forth in Section 8.2.3.6.

8.6.2 Right to Self-Provide.

Each Scheduling Coordinator may choose to self-provide all, or a portion, of its Regulation, Operating Reserve, and Replacement Reserve obligation in each Zone. The ISO shall schedule self-provided Ancillary Services, Day-Ahead and Hour-Ahead, and Dispatch self-provided Ancillary Services in real time. To the extent that a Scheduling Coordinator self-provides, the ISO shall correspondingly reduce the quantity of the Ancillary Services concerned, which it procures as described in Sections 8.5.6 to 8.5.8A. In accordance with Section 34.8 and Section 8.10.2.2, if a Scheduling Coordinator uses capacity scheduled to self-provide Spinning Reserve, Non-Spinning Reserve, or Replacement Reserve to supply Uninstructed Imbalance Energy to the ISO from a Generating Unit, Curtailable Demand, or System Resource under circumstances that would cause the elimination of payments to the Scheduling Coordinator under Section 8.10.2.2 if the capacity had been bid and was selected by the ISO to supply the Ancillary Service, the Scheduling Coordinator shall pay to the ISO the amount of the payment that would be eliminated under that section. Scheduling Coordinators may trade Ancillary Services obligations so that any Scheduling Coordinator may reduce its Ancillary Services obligation through purchase of Ancillary Services capacity from another Scheduling Coordinator, or self-provide in excess of its obligation to sell Ancillary Services to another Scheduling Coordinator, subject to the limits specified under Section 8.6.4.2. If a Scheduling Coordinator's Day-Ahead self-provided Ancillary Service Schedule is decreased in the Hour-Ahead Market, such decrease shall be deemed to be replaced at the Market Clearing Price in the Hour-Ahead Market, pursuant to Section 8.7.

8.6.3 Services Which May Be Self-Provided.

The ISO shall permit Scheduling Coordinators to self-provide the following Ancillary Services:

- (a) Regulation;
- (b) Spinning Reserve;

- (c) Non-Spinning Reserve; and
- (d) Replacement Reserve.

The ISO may from time to time add other Ancillary Services to this list as it considers appropriate.

8.6.4 Time Frame for Informing ISO of Self-Provision.

8.6.4.1 Day-Ahead Schedule.

At the Day-Ahead scheduling process, Scheduling Coordinators shall be required to submit information on self-provided Ancillary Services within the time frame stated in Section 8.5.2.1. Failure to submit the required information within the stated time frame for any hour shall lead to the self-provision for that hour being declared invalid by the ISO, and under such circumstances the ISO shall purchase sufficient Ancillary Services to meet the Scheduling Coordinator's requirements to match its Day-Ahead Schedule.

8.6.4.2 Hour-Ahead Schedule.

Increases in each Scheduling Coordinator's self-provided Ancillary Service between the Day-Ahead and Hour-Ahead Markets shall be limited to the estimated incremental Ancillary Service requirement associated with the increase between the Day-Ahead and Hour-Ahead Markets in that Scheduling Coordinator's scheduled Zonal Demand. Notwithstanding this limit on increases in Hour-Ahead self-provision, a Scheduling Coordinator may buy or sell Ancillary Services through Inter-Scheduling Coordinator Ancillary Service Trades in the Hour-Ahead Market. In the Hour-Ahead scheduling process, Scheduling Coordinators shall be required to submit information on self-provided Ancillary Services within the time frame stated in Section 8.5.2.2. Failure to submit the required adjusted information within the stated time frame shall lead to the self-provision being declared invalid by the ISO, and under such circumstances the ISO shall purchase the additional Ancillary Services necessary to meet the requirements for that Scheduling Coordinator.

8.6.4.2A Information To Be Submitted By Scheduling Coordinators For Each Service.

Scheduling Coordinators electing to self-provide Ancillary Services shall submit the information for each self-provided Ancillary Service as described in Sections 8.5.6 to 8.5.8A, excluding the capacity price

information, but including the name of the trading Scheduling Coordinator in the case of Inter-Scheduling Coordinator Ancillary Service Trades.

In the event of an Inter-Scheduling Coordinator Ancillary Service Trade, the Scheduling Coordinators who are parties to that trade must agree on a Zone in which the trade is deemed to take place and notify the ISO accordingly. The Ancillary Service obligations in the Zone of each Scheduling Coordinator will be adjusted to reflect the trade. The Inter-Scheduling Coordinator Ancillary Service Trades section of a Schedule will include the following information for each Inter-Scheduling Coordinator Ancillary Service Trade.

- (a) Scheduling Coordinator's ID code;
- (b) Type of market (Day-Ahead or Hour-Ahead) and Trading Day;
- (c) Trading Scheduling Coordinator (buyer or seller);
- (d) Zone;
- (e) Schedule type-Regulation Up (ARGU), Regulation Down (ARGD), Spinning Reserve (ASPN), Non-Spinning Reserve (ANSP) or Replacement Reserve (AREP); and
- (f) Contracted MW amount of traded Ancillary Service obligation.

8.6.4.3 Acceptance of Self-Provided Ancillary Service Schedules.

The ISO will refuse to accept self-provided Ancillary Service Schedules only to the extent that they fail to meet requirements contained in this ISO Tariff. In particular, self-provided Ancillary Service Schedules must satisfy the following conditions:

- (a) the Scheduling Coordinator has a current certificate of technical eligibility for the Generating Units, System Units, Loads or System Resources selected for the Ancillary Services in question;
- (b) to the extent not provided under (a), the Generating Units, System Units, Loads and System Resources have the instrumentation, communication and metering equipment necessary to permit the ISO to dispatch the offered Ancillary Services and verify that the services have been provided;

- (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

Dispatch instructions, and by analysis of the appropriate Meter Data, or interchange schedules. The ISO may test the capability of any Generating Unit, System Unit, System Resource, external import of a System Resource, Load providing Curtailable Demand, or reactive device providing ancillary services. Participating Generators, owners or operators of Loads, operators of System Units or System Resources, owners or operators of reactive devices and Scheduling Coordinators shall notify the ISO immediately whenever they become aware that an Ancillary Service is not available in any way. All Participating Generators, owners or operators of Loads, operators of System Units or System Resources and owners or operators of reactive devices shall check, monitor and/or test their system and related equipment routinely to assure availability of the committed Ancillary Services. These requirements apply whether the Ancillary Services are contracted or self-provided. For a duration specified by the ISO, the ISO may suspend the technical eligibility certificate of a Scheduling Coordinator for a Generating Unit, System Unit, Load or System Resource, which repeatedly fails to perform. The ISO shall develop measures to discourage repeated non-performance on the part of both bidders and self-providers.

8.10A Compliance Testing for Regulation. The ISO may test the capability of any Generating Unit or System Resource providing Regulation by using the ISO EMS to move that Generating Unit's or System Resource's output over the full range of its Regulation capacity within a ten-minute period.

8.10B [Not Used]

8.10C Compliance Testing for Non-Spinning Reserve.

(a) Compliance Testing of a Generating Unit, System Unit or System Resource. The ISO may test the Non-Spinning Reserve capability of a Generating Unit, System Unit or an external import of a System Resource by issuing unannounced Dispatch instructions requiring the Generating Unit or System Unit to come on line and ramp up or, in the case of a System Resource, to affirmatively respond to real-time interchange schedule adjustment; all in accordance with the Scheduling Coordinator's bid. Such tests may not necessarily occur on the hour. The ISO shall measure the response of the Generating

Unit, System Unit or external import of a System Resource to determine compliance with its stated capabilities.

- (b) Compliance Testing of Curtailable Demand. The ISO may test the Non-Spinning Reserve capability of a Load providing Curtailable Demand by issuing unannounced Dispatch instructions requiring the operator of the Load to report the switchable Demand of that Load actually being served by the operator at the time of the instruction. No Load will be disconnected as part of the test.

8.10D Compliance Testing for Replacement Reserve.

- (a) Compliance Testing of a Generating Unit, System Unit or System Resource. The ISO may test the Replacement Reserve capability of a Generating Unit, System Unit or an external import of a System Resource by issuing unannounced Dispatch instructions requiring the Generating Unit or System Unit to come on line and ramp up or, in the case of a System Resource, to affirmatively respond to a real-time interchange schedule adjustment; all in accordance with the Scheduling Coordinator's bid. Such tests may not necessarily occur on the hour. The ISO shall measure the response of the Generating Unit, System Unit or external import of a System Resource to determine compliance with its stated capabilities.
- (b) Compliance Testing of a Curtailable Demand. The ISO may test the Replacement Reserve capability of a Load providing Curtailable Demand by issuing unannounced Dispatch instructions requiring the operator of the Load to report the switchable Demand of that Load actually being served by the operator at the time of the instruction. No Load will be disconnected as part of a test.

8.10E Compliance Testing for Voltage Support.

- (a) Compliance Testing of a Generating Unit. The ISO may test the Voltage Support capability of a Generating Unit by issuing unannounced Dispatch instructions requiring

the Generating Unit to adjust its power factor outside the specified power factor band of 0.90 lag to 0.95 lead, but within the limits of the Generating Unit capability curve.

- (b) Compliance Testing of Other Reactive Devices. The ISO may test the Voltage Support capability of other reactive devices (shunt capacitors, static var compensators, synchronous condensers) by issuing unannounced Dispatch instructions requiring operation of such devices.

8.10F Compliance Testing for Black Start. The ISO may test the Black Start capability of a Generating Unit by unannounced tests, which may include issuing Dispatch instructions to start and synchronize the resource, testing of all communications circuits, simulating switching needed to connect the Black Start Generating Unit to the transmission system, and testing the features unique to each facility that relate to Black Start service.

8.10F.1 Consequences of Failure to Pass Compliance Testing.

- (a) Notification of Compliance Testing Results. If a Generating Unit, Load, or System Resource fails a compliance test, the ISO shall notify the Scheduling Coordinator whose resource was the subject of the test and the Ancillary Service Provider or owner or operator of a System Resource providing Ancillary Services of such failure by any means as soon as reasonably practicable after the completion of the test. In addition, regardless of the outcome of the test, the ISO shall provide the Scheduling Coordinator whose resource was subject to a compliance test written notice of the results of such test. The ISO shall at the same time send a copy of the notice to the Ancillary Service Provider or owner or operator of a System Resource providing Ancillary Services.
- (b) Penalties for Failure to Pass Compliance Testing. The Scheduling Coordinator whose resource fails a compliance test shall be subject to the financial penalties provided for in the ISO Tariff. In addition, the ISO shall institute the sanctions described in Section 8.10N.

8.10G Performance Audits for Standard Compliance. In addition to testing under Section 8.10.1, the ISO will periodically audit the performance of resources providing Ancillary Services to confirm the ability of such resources to meet the applicable Ancillary Service standard for performance and control.

8.10G.1 Performance Audit for Regulation. The ISO will audit the performance of a Generating Unit providing Regulation by monitoring its response to ISO EMS control or, in the case of an external import of a System Resource providing Regulation, by monitoring the dynamic interchange response to ISO EMS control around its Set Point within its rated MW/minute capability over the range of Regulation capacity scheduled for the current Settlement Period.

8.10H Performance Audit for Spinning Reserve. The ISO will audit the performance of a Generating Unit or external import of a System Resource providing Spinning Reserve by auditing its response to Dispatch instructions and by analysis of Meter Data associated with the Generating Unit. Such audits may not necessarily occur on the hour. A Generating Unit providing Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move at the MW/minute capability stated in its bid, reach the amount of Spinning Reserve capacity scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO, and respond to system frequency deviations outside the allowed frequency deadband. An external import of a System Resource providing Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move at the MW/minute capability stated in its bid, reach the amount of Spinning Reserve capacity scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO.

8.10I Performance Audit for Non-Spinning Reserve. The ISO will audit the performance of a Generating Unit, Load, or System Resource providing Non-Spinning Reserve by auditing its response to Dispatch instructions, and by analysis of Meter Data associated with the resource. Such audits may not necessarily occur on the hour. A Generating Unit providing Non-Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move in accordance with the time delay and MW/minute capability stated in its bid, and reach the amount of Non-Spinning Reserve capacity under the control of the ISO scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction

by the ISO. An external import of a System Resource providing Non-Spinning Reserve shall be evaluated on its ability to respond to a Dispatch instruction, move in accordance with the time delay and MW/minute capability stated in its bid, and reach the amount of Non-Spinning Reserve capacity scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO. A Load providing Non-Spinning Reserve from Curtailable Demand shall be evaluated on its ability to respond to a Dispatch instruction, move in accordance with the time delay and MW/minute capability stated in its bid, and reach the amount of Non-Spinning Reserve capacity scheduled for the current Settlement Period within ten minutes of issue of the Dispatch instruction by the ISO.

8.10J Performance Audit for Replacement Reserve. The ISO will audit the performance of a Generating Unit, Load, or System Resource providing Replacement Reserve by auditing its response to Dispatch instructions, and by analysis of Meter Data associated with the resource. Such audits may not necessarily occur on the hour. A Generating Unit providing Replacement Reserve shall be evaluated on its ability to respond to a Dispatch instruction, start within the designated time delay, move at the MW/minute capability stated in its bid, reach the amount of Replacement Reserve capacity scheduled for the Settlement Period concerned within sixty minutes of issue of the Dispatch instruction, and sustain operation at this level for a sufficient time to assure availability over the specified period. An external import of a System Resource providing Replacement Reserve shall be evaluated on its ability to respond to a Dispatch instruction, start within the designated time delay, move at the MW/minute capability stated in its bid, reach the amount of Replacement Reserve capacity scheduled for the Settlement Period concerned within sixty minutes of issue of the Dispatch instruction, and sustain operation at this level for a sufficient time to assure availability over the specified period. A Load providing Replacement Reserve from Curtailable Demand shall be evaluated on its ability to respond to a Dispatch instruction, start within the designated time delay, move at the MW/minute capability stated in its bid, reach the amount of Replacement Reserve capacity scheduled for the Settlement Period concerned within sixty minutes of issue of the Dispatch instruction, and sustain operation at this level for a sufficient time to assure availability over the specified period.

8.10K Performance Audit for Voltage Support. The ISO will audit the performance of a resource providing Voltage Support by auditing of its response to Dispatch instructions, and by analysis of Meter Data associated with the resource. A resource providing Voltage Support shall be evaluated on its ability to provide reactive support over the stated power factor range of the resource, provide reactive support within the prescribed time periods, and demonstrate the effective function of automatic voltage control equipment for the amount of Voltage Support under the control of the ISO for the current Settlement Period.

8.10L Performance Audit for Black Start. The ISO will audit the performance of a Black Start Generating Unit by analysis of Meter Data and other records to determine that the performance criteria relating to the Black Start from that Black Start Generating Unit were met when required.

8.10M Consequences of Failure to Pass Performance Audits.

- (a) Notification of Performance Audit Results. The ISO shall give the Scheduling Coordinator for an Ancillary Service Provider whose resource was subject to a performance audit written notice of the results of such audit. The ISO will at the same time send a copy of the notice to the Ancillary Service Provider.
- (b) Penalties for Failure to Pass Performance Audit. The Scheduling Coordinator for an Ancillary Service Provider whose resource fails a performance audit shall be subject to the financial penalties provided for in the ISO Tariff. In addition the sanctions described in Section 8.10 shall come into effect.

8.10N Sanctions for Poor Performance.

8.10N.1 Warning Notice. If an Ancillary Service resource fails a compliance test or a performance audit, the ISO will issue a warning notice to the Scheduling Coordinator for that resource and at the same time will send a copy of the notice to the owner and operator of the resource.

8.10N.2 Scheduling Coordinator's Option to Test. On receipt of a warning notice the Ancillary Service Provider for the resource concerned may request the ISO, through its Scheduling Coordinator, to test the capability of the Ancillary Service resource concerned. The ISO shall carry out such test as soon

as practicable and the cost of such test shall be paid by the Scheduling Coordinator irrespective of the result of the test.

8.10N.3 Duration of Warning Notice. A warning notice shall continue in effect until:

- (a) the Ancillary Service resource is next tested by the ISO whether such a test is called for by the Scheduling Coordinator under Section 8.10N.2 or carried out by the ISO under Section 8.10; or
- (b) the expiration of a period of six calendar months from the date upon which the ISO notified the Scheduling Coordinator that the Ancillary Service resource failed the test or the performance audit which gave rise to the issue of the warning notice, whichever is the earlier.

8.10P Second failure. An Ancillary Service resource which fails a compliance test or a performance audit conducted during the period when a warning notice for that resource is in effect shall be disqualified immediately from providing the Ancillary Service concerned whether as part of the ISO's auction or as part of a self-provision arrangement, and shall not be permitted to submit a bid to the ISO or be part of a self-provision arrangement until such time as it has successfully re-passed the approval and certification procedure described in the relevant Part of Appendix K.

8.10.1 Periodic Testing of Units.

The ISO shall periodically conduct unannounced tests of resources providing Ancillary Services to confirm the ability of such resources to meet the applicable Ancillary Service standard for performance and control. The ISO may test Generating Units, System Units, Loads and System Resources in the manner described herein. The frequency of testing shall be within such timeframes as are reasonable under all the circumstances. Scheduling Coordinators shall manage the resulting Energy output if notification of testing permits the Energy to be scheduled. If a Generating Unit, System Unit, Load, or System Resource fails to meet requirements in a test under this section, the ISO shall notify the relevant Participating Generator, owner or operator of Loads, System Units or System Resources, or Scheduling

Coordinator of such failure as soon as reasonably practicable after the completion of the test. Failure to meet requirements shall lead to the penalties described in Section 2.5.26.

8.10.1.1 Regulation. The ISO shall continuously monitor the response of a Generating Unit, System Unit, or System Resource to the ISO's Regulation instructions in order to determine compliance with Dispatch instructions.

8.10.1.2 Spinning Reserve. The ISO shall test the Spinning Reserve capability of a Generating Unit, System Unit or System Resource by issuing unannounced Dispatch instructions requiring the Generating Unit, System Unit or System Resource to ramp up to its ten minute capability. The ISO shall measure the response of the Generating Unit, System Unit or System Resource to determine compliance with requirements. Such tests may not necessarily occur on the hour. The Scheduling Coordinator for the Generating Unit, System Unit or System Resource shall be paid the Energy Bid price of the Generating Unit or System Unit for the output under the Spinning Reserve test.

8.10.1.3 Non-Spinning Reserve. The ISO may test the Non-Spinning Reserve capability of a Generating Unit, Load, System Unit or System Resource by issuing unannounced Dispatch instructions requiring the Generating Unit, Load, System Unit or System Resource to come on line and ramp up or to reduce Demand to its ten minute capability. The ISO shall measure the response of the Generating Unit, System Unit, System Resource or Load to determine compliance with requirements. The Scheduling Coordinator for the Generating Unit, System Unit, Load or System Resource shall be paid the Energy (or Demand reduction) Bid price of the Generating Unit, System Unit, Load or System Resource for its output or reduction, under the Non-Spinning Reserve test.

8.10.1.4 Replacement Reserve. The ISO may test the Replacement Reserve capability of a Generating Unit, Load, System Unit or System Resource by issuing unannounced Dispatch instructions requiring the Generating Unit, Load, System Unit or System Resource to come on line and ramp up or reduce Demand to its sixty minute capability. The ISO shall measure the response of the Generating Unit, Load, System Unit or System Resource to determine compliance with requirements. The Scheduling Coordinator for the Generating Unit, Load, System Unit or System Resource shall be paid the Energy or

Demand reduction Bid price of the Generating Unit, Load, System Unit or System Resource for the output, or reduction, of the Generating Unit, Load, System Unit or System Resource under the Replacement Reserve test.

8.10.1.5 Voltage Support. The ISO shall monitor a Generating Unit's response to Voltage Support instructions in order to determine compliance with Dispatch instructions.

8.10.1.6 Black Start. The ISO may test the Black Start capability of a Generating Unit by issuing unannounced dispatch instructions requiring the Generating Unit to start on a Black Start basis. The ISO shall measure the response of the Generating Unit to determine compliance with the terms of the Black Start contract. The Scheduling Coordinator or Black Start Generator as stated in Section 8.11.5 for the Generating Unit shall be paid the Generating Unit's contract price for the output under the Black Start test.

8.10.2 Penalties for Failure to Pass Tests and Rescission of Payment for Non-Delivery.

8.10.2.1 Penalties for Failure to Pass Tests.

A Generating Unit, Curtailable Demand, System Unit or System Resource that fails an availability test, as determined under criteria to be established by the ISO, shall be deemed not to have been available to provide the Ancillary Service concerned or the relevant portion of that Service for the entire period the Generating Unit, Curtailable Demand, System Unit or System Resource was committed to provide the Service, unless appropriate documentation (i.e., daily test records) confirming the availability of that service during the committed period(s) is presented to the ISO. The "committed period" is defined as the total of all the hours/days the Generating Unit, Curtailable Demand, System Unit or System Resource was scheduled by the ISO to provide the Ancillary Service beginning from: (i) the last successful availability test; or (ii) the last time the Generating Unit, Curtailable Demand, System Unit or System Resource actually provided Energy or reduced Demand as part of the Ancillary Service; whichever results in a shorter committed period. The Scheduling Coordinator for a Generating Unit, Curtailable Demand, System Unit or System Resource that fails an availability test shall not be entitled to payment for the Ancillary Service concerned for the committed period and adjustments to reflect this shall be made in the calculation of payments to the Scheduling Coordinator, provided that any such penalty shall be reduced

to reflect any adjustment made over the duration of the committed period under Section 8.10.2.2 or 8.10.2.3.

System Units engaged in self-provision of Ancillary Services, or providing Ancillary Services to the ISO are subject to the same testing, compensation, and penalties as are applied to individual Generating Units engaged in self-provision or provision of Ancillary Services. To perform testing, the ISO will bias the MSS's MSRE to test the responsiveness of the System Unit.

If payments for capacity for a particular Ancillary Service in a particular Settlement Period would be rescinded under more than one provision of this Section 8.10.2, the total amount to be rescinded for a particular Ancillary Service in a particular Settlement Period shall not exceed the total payment due in that Settlement Period.

8.10.2.2 Rescission of Payments for Unavailability.

If capacity scheduled into the ISO's Ancillary Services markets from a Generating Unit, Curtailable Demand, System Unit or System Resource is unavailable during the relevant Settlement Interval, then payments will be rescinded as described herein. For self-provided Ancillary Services, the payment obligation shall be equivalent to that which would arise if the Ancillary Services had been bid into each market in which they were scheduled.

8.10.2.2.1 If the ISO determines that a Scheduling Coordinator has supplied Uninstructed Imbalance Energy to the ISO during a Settlement Interval from the capacity of a Generating Unit, System Unit or System Resource that is obligated to supply Spinning Reserve, Non-Spinning Reserve, or Replacement Reserve to the ISO during such Settlement Interval, payments to the Scheduling Coordinator representing the Generating Unit, System Unit or System Resource for the Ancillary Service capacity used to supply Uninstructed Imbalance Energy shall be eliminated to the extent of the deficiency, except to the extent (i) the deficiency in the availability of Ancillary Service capacity from the Generating Unit, System Unit or System Resource is attributable to control exercised by the ISO in that Settlement Interval through AGC operation, an RMR Dispatch Notice, or dispatch to avoid an intervention in Market

operations or to prevent a System Emergency; or (ii) a penalty is imposed under Section 8.10.2.1 with respect to the deficiency.

8.10.2.2.2 If a Curtailable Demand is insufficient to deliver the full amount of the Non-Spinning and Replacement Reserve to which that Curtailable Demand is obligated in that Settlement Interval, then the related capacity payments will be rescinded to the extent of that deficiency as explained in Section 8.10.2.2.4 and 8.10.2.2.5, unless a penalty is imposed on that Curtailable Demand for that Settlement Interval under Section 8.10.2.1.

8.10.2.2.3 The ISO shall calculate the real-time ability of each Generating Unit and System Unit to deliver Energy from Ancillary Services capacity awarded or self-provided for each Settlement Interval based on its operational ramp rate as described in Section 30.4.6, maximum operating capability, and actual telemetered output. If the Generating Unit or System Unit cannot deliver the full amount of Energy from the awarded or self-provided Spinning, Non-Spinning or Replacement Reserve for a Settlement Interval then Ancillary Services capacity payments for the amount of Energy that cannot be delivered for the particular Settlement Interval shall be rescinded.

8.10.2.2.4 This Section 8.10.2.2.4 shall not apply to the capacity payment for any particular Ancillary Service if the Zonal Market Clearing Price determined in accordance with Sections 8.5.7, 8.5.8 or 8.5.8A is less than or equal to zero. For those Ancillary Services for which such Zonal Market Clearing Prices are greater than zero, the payment for Ancillary Service capacity otherwise payable under Section 8.11.2, 8.11.3, and/or 8.11.3A shall be reduced by one sixth of the product of the applicable prices and the amount of Ancillary Service capacity from which the Generating Unit, Curtailable Demand, System Unit or System Resource has supplied Uninstructed Imbalance Energy in a Settlement Interval. If a Scheduling Coordinator schedules Ancillary Services through both the Day-Ahead and Hour-Ahead Markets, capacity payments due the Scheduling Coordinator from each market will be rescinded in proportion to the amount of capacity sold to the ISO in each market.

8.10.2.2.5 Payment shall be eliminated first for any Replacement Reserve capacity for which the Generating Unit, Curtailable Demand, System Unit or System Resource would otherwise be entitled to

payment. If the amount of Ancillary Service capacity from which the Generating Unit, System Unit or System Resource has supplied Uninstructed Imbalance Energy exceeds the amount of Replacement Reserve capacity for which it would otherwise be entitled to receive payment, payment shall be eliminated for Non-Spinning Reserve capacity, and then for Spinning Reserve capacity, until payment has been withheld for the full amount of Ancillary Service capacity from which the Generating Unit, Curtailable Demand, System Unit or System Resource supplied Uninstructed Imbalance Energy.

8.10.2.2.6 For each Settlement Interval in which a Generating Unit, Curtailable Demand, System Unit or System Resource fails to actually supply Energy from Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity in accordance with a Dispatch Instruction, or supplies only a portion of the Energy specified in the Dispatch Instruction, the capacity payment will be pro-rated to reflect the unavailability in that Settlement Interval of the difference between (1) the total MW of the particular Ancillary Service scheduled in that Settlement Period and (2) the amount of Energy, if any, supplied in response to the Dispatch Instruction in that Settlement Interval.

8.10.2.3 Rescission of Payments When Dispatch Instruction is Not Followed.

If the total metered output of a Generating Unit, Curtailable Demand, System Unit or System Resource is insufficient to supply the amount of Instructed Imbalance Energy associated with a Dispatch Instruction issued in accordance with a bid on Spinning Reserve, Non-Spinning Reserve, or Replacement Reserve in any Settlement Interval, then the capacity payment associated with the difference between the total scheduled amount of each Ancillary Service for which Insufficient Energy was delivered, and the actual output attributed to the response to the Dispatch Instruction on each Ancillary Service, shall be rescinded. However, no capacity payment shall be rescinded if the shortfall in the metered output of the Generating Unit, Curtailable Demand, System Unit, or System Resource is less than a deadband amount published by ISO on the ISO Home Page at least twenty-four hours prior to the Settlement Interval. For any Settlement Interval with respect to which no deadband amount has been published by the ISO, the deadband amount shall be zero MWH. If the Generating Unit, Curtailable Demand, System Unit or System Resource is scheduled to provide more than one Ancillary Service in the Settlement Period, then the actual output will be attributed first to Replacement Reserve, then to Non-Spinning Reserve, and

finally to Spinning Reserve, and the capacity payments associated with the balance of each Ancillary Service shall be rescinded. If the same Ancillary Service is scheduled in both the Day-Ahead and Hour-Ahead Markets, then payments shall be rescinded in proportion to the amount of each Ancillary Service scheduled in each market.

8.10.2.4 Penalties applied pursuant to Section 8.10.2.1, and payments rescinded pursuant to Section 8.10.2.2 and 8.10.2.3 shall be redistributed to Scheduling Coordinators in proportion to ISO Control Area metered Demand and scheduled exports for the same Trading Day.

8.10.2.5 If the ISO determines that non-compliance of a Load, Generating Unit, System Unit or System Resource, with an operating order or Dispatch Instruction from the ISO, or with any other applicable technical standard under the ISO Tariff, causes or exacerbates system conditions for which the WECC imposes a penalty on the ISO, then the Scheduling Coordinator of such Load, Generating Unit, System Unit or System Resource shall be assigned that portion of the WECC penalty which the ISO reasonably determines is attributable to such non-compliance, in addition to any other penalties or sanctions applicable under the ISO Tariff.

8.10.2.6 Temporary Exemption from Rescission of Energy Payments.

Any Participating Load that has entered into a Participating Load Agreement and has responded to a Dispatch Instruction will be exempt from the requirements of Section 8.10.2.2.3 in the hour of the Dispatch and for the following two (2) hours during the period beginning on June 15, 2000 and ending on the date specified in a notice ("Notice Terminating Temporary Exemption") to be issued by the ISO. Such notice shall be posted on the ISO Home Page and distributed to Market Participants via e-mail at least seven (7) calendar days in advance of the termination of this temporary exemption.

8.11 Settlements For Contracted Ancillary Services.

Based on the prices and quantities determined in accordance with this Section, the ISO shall operate a daily Settlement function for Ancillary Services it contracts for with Scheduling Coordinators.

The ISO shall calculate imbalances between scheduled, instructed and actual quantities of Energy provided based upon Meter Data obtained pursuant to Section 10. Schedules between Control

Areas shall be deemed as being delivered in accordance with Good Utility Practice. Dynamic schedules shall be integrated over time through the operating hour and the MWh quantity obtained by such integration shall be deemed to be the associated scheduled interchange for that operating hour. The difference between actual and scheduled interchange shall then be addressed in accordance with the WECC and NERC inadvertent interchange practices and procedures. Following this practice, all dynamic schedules for Ancillary Services provided to the ISO from System Resources in other Control Areas shall be deemed delivered to the ISO. The difference between the Energy requested by the ISO and that actually delivered by the other Control Area shall then be accounted for and addressed through the WECC and NERC inadvertent interchange practices and procedures.

Separate payments shall be calculated for each Settlement Period t for each Generating Unit, System Unit, System Resource and Curtailable Demand. The ISO shall then calculate a total daily payment for each Scheduling Coordinator for all the Generating Units, System Units, System Resources and Curtailable Demands that it represents for each Settlement Period t .

The settlements for the Hour-Ahead Markets shall be calculated by substituting Hour-Ahead prices in the relevant formulae and deducting any amounts due to the ISO from Scheduling Coordinators who buy back in the Hour-Ahead Market Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity they sold to the ISO in the Day-Ahead Market.

8.11.1 Regulation.

Regulation Up and Regulation Down payments shall be calculated separately.

Quantities. The following quantity definitions shall be used for each Scheduling Coordinator in the settlement process:

$AGCU_{pQDA_{xt}}$ = the Scheduling Coordinator's total quantity of Regulation Up capacity in Zone X sold through the ISO auction and scheduled Day-Ahead j for Settlement Period t .

$AGCDown_{QDA_{xt}}$ = the Scheduling Coordinator's total quantity of Regulation Down capacity in Zone X sold through the ISO auction and scheduled Day-Ahead j for Settlement Period t .

$EnQInst_{xt}$ = Instructed Imbalance Energy increase or decrease in Zone X in real-time Dispatch for each Dispatch Interval b of Settlement Period t, determined in accordance with the ISO Protocols.

Prices. The prices in the Settlement process for Regulation Up and Regulation Down shall be those determined in Section 8.5.6.

Adjustment: penalty described in Section 8.10.2.1.

$PAGCUpDA_{xt}$ = the Market Clearing Price, PAGC, in Zone X for Regulation Up capacity in the Day-Ahead Market for Settlement Period t.

$PAGCDownDA_{xt}$ = the Market Clearing Price, PAGC, in Zone X for Regulation Down capacity in the Day-Ahead Market for Settlement Period t.

Payments. Scheduling Coordinators for Generating Units providing Regulation Up capacity through the ISO auction shall receive the following payments for Regulation Up:

$$AGCUpPay_{xt} = AGCUpQDA_{xt} * PAGCUpDA_{xt} - Adjustment$$

Scheduling Coordinators for Generating Units providing Regulation Down capacity through the ISO auction shall receive the following payments for Regulation Down:

$$AGCDownPay_{xt} = AGCDownQDA_{xt} * PAGCDownDA_{xt} - Adjustment$$

Scheduling Coordinators for Generating Units shall receive the following payment for Energy output from Regulation in accordance with the settlement for Instructed Imbalance Energy under Section 11.2.4.1:

$REPA_{ixt}$ = the Regulation Energy Payment Adjustment for Generating Unit i in Zone X for

$$\sum_i [(EnQInst_{ixt} * Zonal Settlement Interval ExPost Price in Zone X) + REPA_{ixt}]$$

Settlement Period t calculated as follows:

$$[(R_{UPixt} * C_{UP}) + (R_{DNixt} * C_{DN})] * \max(\$20/MWh, P_{xt})$$

Where

R_{UPixt} = the upward range of generating capacity for the provision of Regulation from Generating Unit i in Zone X included in the bid accepted by the ISO for Generating Unit i for Settlement Period t , weighted in proportion to the ISO's need for upward Regulation. The weighting factors will be specified within a range from 0-100 percent. The weighting factors will be set at the discretion of the ISO based on system conditions, and will be set at a level that will provide sufficient incentive to the market to supply upward Regulation for the ISO's purposes of satisfying WECC criteria and NERC control performance standards. The ISO shall post the weighting factors consistent with the ISO Weighting Procedure, posted on the ISO website.

R_{DNixt} = the downward range of generating capacity for the provision of Regulation for Generating Unit i in Zone X included in the bid accepted by the ISO for Generating Unit i for Settlement Period t , weighted in proportion to the ISO's need for downward Regulation. The weighting factors will be specified within a range from 0-100 percent. The weighting factors will be set at the discretion of the ISO based on system conditions, and will be set at a level that will provide sufficient incentive to the market to supply downward Regulation for the ISO's purposes of satisfying WECC criteria and NERC control performance standards. The ISO shall post the weighting factors consistent with the ISO Weighting Procedure, posted on the ISO website.

C_{UP} = 0 to 1

C_{DN} = 0 to 1

P_{xt} = the Hourly Ex Post Price for Zone X in Settlement Period t .

The ISO may modify the value of the constants C_{UP} or C_{DN} within a range of 0-1 either generally in regard to all hours or specifically in regard to particular times of the day, after the ISO Governing Board

approves such modification, by a notice issued by the Chief Executive Officer of the ISO and posted on the ISO Internet "Home Page," at <http://www.ISO.com>, or such other Internet address as the ISO may publish from time to time, specifying the date and time from which the modification shall take effect, which shall be not less than seven (7) days after the Notice is issued.

REPA shall not be payable unless the Generating Unit is available and capable of being controlled and monitored by the ISO Energy Management System over the full range of its Scheduled Regulation capacity for the entire Settlement Period at least the ramp rates (increase and decrease in MW/minute) stated in its bid. In addition, the total Energy available (R_{UP} plus R_{DN}) may be adjusted to be only R_{UP} or only R_{DN} , a percentage of R_{UP} or R_{DN} , or the sum of R_{UP} and R_{DN} , depending on the needs of the ISO for each direction of Regulation service.

8.11.2 Spinning Reserve.

Quantities. The following quantity definitions shall be used for each Scheduling Coordinator in the Settlement process:

$SpinQDA_{xt}$ = the Scheduling Coordinator's total quantity of Spinning Reserve capacity in Zone X sold through the ISO auction and scheduled Day-Ahead for Settlement Period t.

$EnQInst_{xt}$ = Instructed Imbalance Energy output in Zone X in real-time Dispatch for Settlement Period t, supplied in accordance with the ISO Protocols.

Prices. The prices in the Settlement process for Spinning Reserve shall be those determined in Section 8.5.7.

$Adjustment$ = penalty described in Section 8.10.2.1, or rescinded capacity payments described in Section 8.10.2.2 or 8.10.2.3.

$PspDA_{xt}$ = Market Clearing Price, Psp , in Zone X for Spinning Reserve capacity in the Day-Ahead Market for Settlement Period t.

Payments. Scheduling Coordinators for Generating Units, System Units, or System Resources providing Spinning Reserve capacity through the ISO auction shall receive the following payments for Spinning Reserve capacity:

$$SpinPay_{xt} = SpinQDA_{xt} * PspDA_{xt} - Adjustment$$

Scheduling Coordinators for Generating Units, System Units, or System Resources shall receive the following payments for Energy output from Spinning Reserve capacity:

$$EnQInst_{xt} * Resource-Specific Settlement Interval Ex Post Price_{xt}$$

8.11.3 Non-Spinning Reserve.

Quantities. The following quantity definitions shall be used for each Scheduling Coordinator in the Settlement process:

$NonSpinQDA_{xt}$ = the Scheduling Coordinator's total Quantity of Non-Spinning Reserve capacity in Zone X sold through the ISO's auction and scheduled Day-Ahead for Settlement Period t.

$EnQInst_{xt}$ = Instructed Imbalance Energy output or Demand reduction in Zone X in real-time Dispatch for Settlement Period t, supplied in accordance with the ISO Protocols.

Prices. The prices in the Settlement process for Non-Spinning Reserve shall be those determined in Section 8.5.8.

$Adjustment$ = penalty described in Section 8.10.2.1, or rescinded capacity payments described in Section 8.10.2.2 or 8.10.2.3.

$PnonspDA_{xt}$ = Market Clearing Price, $Pnonsp$, in Zone X for Non-Spinning Reserve capacity in the Day-Ahead Market for Settlement Period t.

Payments. Scheduling Coordinators for Generating Units, System Units, System Resources, or Loads supplying Non-Spinning Reserve capacity through the ISO auction shall be paid the following for the Non-Spinning Reserve capacity:

$$NonspPay_{xt} = NonSpinQDA_{xt} * PnonspDA_{xt} - Adjustment$$

Scheduling Coordinators for Generating Units, System Units, System Resources or Loads shall receive the following payments for Energy output from Non-Spinning Reserve capacity:

$$EnQInst_{xt} * Resource-Specific Settlement Interval Ex Post Price_{xt}$$

8.11.3A Replacement Reserve.

Quantities. The following quantity definitions shall be used for each Scheduling Coordinator in the Settlement process:

$RepResQDA_{xt}$ = the Scheduling Coordinator's total quantity of Replacement Reserve capacity in Zone X sold through the ISO auction scheduled Day-Ahead for Settlement Period t, and from which Energy has not been generated.

$EnQInst_{xt}$ = Instructed Imbalance Energy output or Demand reduction in Zone X in real-time Dispatch for Settlement Period t, supplied in accordance with the ISO Protocols.

Prices. The prices in the Settlement process for Replacement Reserve shall be those determined in Section 8.5.8A.

$Adjustment$ = penalty described in Section 8.10.2.1, or rescinded capacity payments described in Section 8.10.2.2 or 8.10.2.3.

$PRepResDA_{xt}$ = Market Clearing Price, PRepRes, in Zone X for Replacement Reserve capacity in the Day-Ahead Market for Settlement Period t.

Payments. Scheduling Coordinators for Generating Units, System Units, System Resources, or Loads providing Replacement Reserve capacity through the ISO auction shall receive the following payments for the portion of a Scheduling Coordinator's Replacement Reserve capacity from which Energy has not been generated:

$$RepResPay_{ijt} = (RepResQDA_{xt} -) * PRepResDA_{xt-Adjustment}$$

Scheduling Coordinators shall not receive capacity payments for the portion of a Scheduling Coordinator's Replacement Reserve capacity from which Energy has been generated. The payments for Energy output from Replacement Reserve capacity are calculated as follows:

$$EnQInst_{ijt} * Resource-Specific Settlement Interval Ex Post Price_{xt}$$

8.11.4 Voltage Support.

The total payments for each Scheduling Coordinator shall be the sum of the short-term procurement payments, based on opportunity cost, as described in Section 8.5.9, and the payments under long-term contracts.

8.11.5 Black Start.

Quantities. The following quantities shall be used in the Settlement process:

$EnQBS_{ijt}$ = Energy output from Black Start made by Generating Unit i from Scheduling Coordinator j (or Black Start Generator j, as the case may be) for Settlement Period t, pursuant to the ISO's order to produce.

Prices. The prices used in the Settlement process are those described in the contracts referred to in Section 8.5.10.

Adjustment = penalty described in Section 8.10.2.1.

Payments. Scheduling Coordinators for owners of Reliability Must-Run Units (or Black Start Generators, as the case may be) shall receive the following payments for Energy output from Black Start facilities:

$$BSEN_{ijt} = (EnQBS_{ijt} * EnBid_{ijt}) + BSSUP_{ijt-Adjustment}$$

where $BSSUP_{ijt}$ is the start-up payment for a Black Start successfully made by Generating Unit i of Scheduling Coordinator j (or Black Start Generator j) in Trading Interval t calculated in accordance with the applicable Reliability Must-Run Contract (or the Interim Black Start Agreement as the case may be).

8.12 Settlement for User Charges for Ancillary Services.

(a) The ISO shall determine a separate hourly user rate for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve for each Settlement Period purchased in the Day-Ahead Market, and in the Hour-Ahead Market. Each rate will be charged to Scheduling Coordinators on a volumetric basis applied to each Scheduling Coordinator's obligation for the Ancillary Service

concerned which it has not self-provided, as adjusted by any Inter-Scheduling Coordinator Ancillary Service Trades.

Each Scheduling Coordinator's obligation for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve for each Zone shall be calculated in accordance with Section 8.6.1, notwithstanding any adjustment to the quantities of each Ancillary Service purchased by the ISO in accordance with Section 8.2.3.6.

The cost of Voltage Support and Black Start shall be allocated to Scheduling Coordinators as described in Sections 8.12.4 and 8.12.5.

Quantities and rates for the Hour-Ahead Markets shall be calculated by substituting the Hour-Ahead quantities and prices in the relevant formulae (including self-provided quantities of the Ancillary Service) except that the user rates for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve capacity shall be calculated by dividing the net payments made by the ISO for each service by the MW quantity purchased for each service. The net payments are the total payments for each service net of sums payable by Scheduling Coordinators who have bought back in the Hour-Ahead Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity, as the case may be, which they had sold to the ISO in the Day-Ahead Market.

Ancillary Services obligations may be negative, and credits for such negative obligations will be in accordance with the rates calculated in Sections 8.12.1, 8.12.2, 8.12.3 and 8.12.3A, except that a Scheduling Coordinator's credit shall be reduced by the greater of: a) the amount of any self-provision scheduled from resources which are deemed to meet the ISO's Ancillary Services standards, and which are not subject to the certification and testing requirements of the ISO Tariff; or b) if the ISO has no incremental requirement to be met in the Hour-Ahead Market for an Ancillary Service, the incremental amount of such service scheduled by that Scheduling Coordinator in the Hour-Ahead Market.

The ISO will allocate the Ancillary Services capacity charges, for both Day-Ahead and Hour-Ahead Markets, on a Zonal basis if the Day-Ahead Ancillary Services market is procured on a Zonal basis. The ISO will allocate the Ancillary Services capacity charges, for both the Day-Ahead and Hour-

Ahead Markets, on an ISO Control Area wide basis if the Day-Ahead Ancillary Services market is defined on an ISO Control Area wide basis.

(b) If, in any Settlement Period, no quantity of Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve is purchased in the Day-Ahead Market or the Hour-Ahead Market due to the operation of Section 8.2.3.6, then in lieu of the user rate determined in accordance with Section 8.12.1, 8.12.2, 8.12.3, or 8.12.3A, as applicable, the user rate for the affected Ancillary Service for that Settlement Period shall be determined as follows:

(i) If the affected market is a Day-Ahead Market, the user rate for the affected Ancillary Service shall be set at the lowest capacity reservation price for an unaccepted qualified capacity bid in the Day-Ahead Market for the same Settlement Period for that Ancillary Service or for another Ancillary Service that meets the requirements for the affected Ancillary Service. If there are no such unaccepted bids, the user rate for the affected Ancillary Service shall be the lowest Market Clearing Price for the same Settlement Period established in the Day-Ahead Market for another Ancillary Service that meets the requirements for the affected Ancillary Service.

(ii) If the affected market is an Hour-Ahead Market, the user rate for the affected Ancillary Service shall be set at the lowest capacity reservation price for an unaccepted qualified capacity bid in the Hour-Ahead Market for the same Settlement Period for that Ancillary Service or for another Ancillary Service that meets the requirements for the affected Ancillary Service. If there are no such unaccepted bids, the user rate for the affected Ancillary Service shall be the user rate for the same Ancillary Service in the Day-Ahead Market in the same Settlement Period.

(c) With respect to each Settlement Period, in addition to the user rates determined in accordance with Sections 8.12.1 through 8.12.3A or Section 8.12(b), as applicable, each Scheduling Coordinator shall be charged an additional amount equal to its proportionate share, based on total purchases by Scheduling Coordinators of Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve of the amount, if any, by which (i) the total payments to Scheduling Coordinators pursuant to Section 8.11.1 through 8.11.3A, for the Day-Ahead Market and Hour-Ahead Market and all

Zones, exceed (ii) the total amounts charged to Scheduling Coordinators pursuant to Section 8.12.1 through 8.12.3A, for the Day-Ahead Market and Hour-Ahead Market and all Zones. If total amounts charged to Scheduling Coordinators exceed the total payments to Scheduling Coordinators, each Scheduling Coordinator will be refunded its proportionate share, based on total purchases by Scheduling Coordinators of Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve.

8.12.1 Regulation.

Regulation Up and Regulation Down charges shall be calculated separately. The user rate per unit of purchased Regulation service for each Settlement Period in the Day-Ahead Market for each Zone shall be calculated by dividing the total Regulation capacity payments by the ISO's total MW purchases of Regulation for that Settlement Period for that Zone which has not been self-provided by Scheduling Coordinators. The ISO will calculate the user rate for Regulation Up in each Zone for each Settlement Period as:

$$RegRateUpDA (\$/MW) = AGCUpPayDA / AGCUpPurchDA$$

where:

$AGCUpPayDA$ = Total Regulation Up payments for the Settlement Period in the Day-Ahead Market for the Zone.

$AGCUpPurchDA$ = the total ISO Regulation Up MW purchases in the Day-Ahead Market for the Settlement Period for the Zone, excluding that which has been self-provided by Scheduling Coordinators.

The ISO will calculate the user rate for Regulation Down in each Zone for each Settlement Period as:

$$RegRateDownDA (\$/MW) = AGCDownPayDA / AGCDownPurchDA$$

where:

$AGCDownPayDA$ = Total Regulation Down payments for the Settlement Period in the Day-Ahead Market for the Zone.

AGCDownPurchDA = the total ISO Regulation Down MW purchases in the Day-Ahead Market for the Settlement Period for the Zone, excluding that which has been self-provided by Scheduling Coordinators.

For each Settlement Period, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each Zone:

$$RegRateUpDA * AGCUpOblig$$

where *AGCUpOblig* is the Scheduling Coordinator's obligation for Regulation Up in the Zone in the Settlement Period for which it has not self-provided.

$$RegRateDownDA * AGCDownOblig$$

where *AGCDownOblig* is the Scheduling Coordinator's obligation for Regulation Down in the Zone in the Settlement Period for which it has not self-provided.

8.12.2 Spinning Reserve.

The user rate per unit of purchased Spinning Reserve for each Settlement Period in the Day-Ahead Market for each Zone shall be calculated by dividing the total capacity payments for Spinning Reserve by the ISO's total MW purchases of Spinning Reserve for that Settlement Period for that Zone which has not been self-provided by Scheduling Coordinators. The ISO will calculate the user rate for Spinning Reserve in each Zone for each Settlement Period as:

$$SpRateDA(\$ / MW) = \frac{SpinPayDA}{SpinPurchDA}$$

where:

SpinPayDA = Total Spinning Reserve payments for the Settlement Period in the Market for the Zone Day-Ahead.

SpinPurchDA = the total ISO Spinning Reserve MW purchases in the Day-Ahead Market for the Settlement Period for the Zone, excluding that which has been self-provided by Scheduling Coordinators.

For each Settlement Period, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each Zone:

$$SPRateDA * SpinOblig$$

where *SpinOblig* is the Scheduling Coordinator's obligation for Spinning Reserve in the Zone in the Settlement Period for which it has not self-provided.

8.12.3 Non-Spinning Reserve.

The user rate per unit of purchased Non-Spinning Reserve for each Settlement Period in the Day-Ahead Market for each Zone shall be calculated by dividing the total capacity payments for Non-Spinning Reserve by the ISO's total MW purchases of Non-Spinning Reserve for that Settlement Period for that Zone which has not been self-provided by Scheduling Coordinators. The ISO will calculate the user rate for Non-Spinning Reserve in each Zone for each Settlement Period as:

$$NonSpRateDA(\$ / MW) = \frac{NonSpinPayDA}{NonSpinPurchDA}$$

where:

NonSpinPayDA = Total Non-Spinning Reserve payments for the Settlement Period in the Day-Ahead Market for the Zone.

NonSpinPurchDA = the total ISO Non-Spinning Reserve MW purchases for the Settlement Period for the Zone, excluding that which has been self-provided by Scheduling Coordinators.

For each Settlement Period, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each Zone:

$$NonSpRateDA * NonSpinOblig$$

where *NonSpinOblig* is the Scheduling Coordinator's obligation for Non-Spinning Reserve in the Zone in the Settlement Period for which it has not self-provided.

8.12.3A Replacement Reserve.

The user rate per unit of Replacement Reserve obligation for each Settlement Period t for each Zone x shall be as follows:

$$ReplRate_{xt} = \frac{(PRepResDA_{xt} * OrigReplReqDA_{xt}) + (PRepResHA_{xt} * OrigReplReqHA_{xt})}{OrigReplReqDA_{xt} + OrigReplReqHA_{xt}}$$

where

$OrigReplReqDA_{xt}$ = Replacement Reserve requirement net of self-provision in the Day-Ahead Market before consideration of any substitutions pursuant to Section 8.2.3.6.

$OrigReplReqHA_{xt}$ = Incremental change in the Replacement Reserve requirement net of self-provision between the Day-Ahead Market and the Hour-Ahead Market before consideration of any substitutions pursuant to Section 8.2.3.6.

$PRepResDA_{xt}$ is the Market Clearing Price for Replacement Reserve in the Day-Ahead Market for Zone x in Settlement Period t .

$PRepResHA_{xt}$ is the Market Clearing Price for Replacement Reserve in the Hour-Ahead Market for Zone x in Settlement Period t .

For each Settlement Period t , each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each Zone x :

$$ReplRate_{xt} * ReplOblig_{jxt}$$

where

$$ReplOblig_{jxt} = DevReplOblig_{jxt} + RemRepl_{jxt} - SelfProv_{jxt} + NetInterSCTrades_{jxt}$$

$DevReplOblig_{jxt}$ is the Scheduling Coordinator's obligation for deviation Replacement Reserve in Zone x in the Settlement Period t and $RemRepl_{jxt}$ is the Scheduling Coordinator's obligation for remaining Replacement Reserve in Zone x for Settlement Period t .

$SelfProv_{jxt}$ is Scheduling Coordinator's Replacement Reserve self-provision in Zone x for Settlement Period t.

$NetInterSCTrades_{jxt}$ is the sale of Replacement Reserve less the purchase of Replacement Reserve through Inter-Scheduling Coordinator Trades by Scheduling Coordinator j in Zone x for Settlement Period t.

Deviation Replacement Reserve for Scheduling Coordinator j in Zone x for Settlement Period t is calculated as follows:

If $ReplObligTotal_{xt} > TotalDeviations_{xt}$ then:

$$DevReplOblig_{xjt} = \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right) \right]$$

If $ReplObligTotal_{xt} < TotalDeviations_{xt}$ then:

$$DevReplOblig_{xjt} = \frac{ReplObligTotal_{xt}}{TotalDeviations_{xt}} * \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right) \right]$$

where,

$$TotalDeviations_{xt} = \sum_j \left[Max\left(0, \sum_i GenDev_{ijxt}\right) - Min\left(0, \sum_i LoadDev_{ijxt}\right) \right]$$

$GenDev_{ijxt}$ = The deviation between scheduled and actual Energy Generation for Generator i represented by Scheduling Coordinator j in Zone x during Settlement Period t as referenced in Part D of Appendix N.

$LoadDev_{ijxt}$ = The deviation between scheduled and actual Load consumption for resource i represented by Scheduling Coordinator j in Zone x during Settlement Period t as referenced in Part D of Appendix N.

$DevReplOblig_{xt}$ is total deviation Replacement Reserve in Zone x for Settlement Period t.

$ReplObligTotal_{xt}$ is total Replacement Reserve Obligation in Zone x for Settlement Period t.

Remaining Replacement Reserve for Scheduling Coordinator j in Zone x for Settlement Period t is calculated as follows:

$$RemRepl_{xjt} = \frac{MeteredDemand_{jxt}}{TotalMeteredDemand_{xt}} * TotalRemRepl_{xt}$$

where:

$MeteredDemand_{jxt}$ is the Scheduling Coordinator's total metered Demand excluding exports in Zone x for Settlement Period t.

$TotalMeteredDemand_{xt}$ is total metered Demand excluding exports in Zone x for Settlement Period t.

$$TotalRemRepl_{xt} = Max[0, ReplObligTotal_{xt} + TotalSelfProv_{xt} - DevReplOblig_{xt}]$$

8.12.4 Voltage Support.

The short-term market Voltage Support user rate for Settlement Period t for Zone x shall be calculated as follows:

$$VSSTRate_{xt} = \frac{\sum_{i,j} VSST_{xijt}}{\sum_j QChargeVS_{xjt}}$$

$VSST_{xijt}$ = Voltage Support payment to Scheduling Coordinator j in respect of Generating Unit i in Zone x in the short-term market applicable to Settlement Period t.

$QChargeVS_{xjt}$ = charging quantity for Voltage Support for Scheduling Coordinator j for Settlement Period t in Zone x equal to the total metered Demand in Zone x (including exports to neighboring Control Areas and excluding metered Demand inside an MSS) by Scheduling Coordinator j for Settlement Period t.

The monthly long-term Voltage Support contract user rate for Settlement Period t for Zone x shall be calculated as follows:

$$VSLTRate_{xm} = \frac{\sum_{i,j} VSLT_{xijm}}{\sum_{jm} QChargeVS_{jt}}$$

where:

$VSLT_{xijm}$ = long-term Voltage Support contract payment to Scheduling Coordinator j for owner of Reliability Must-Run Unit i in Zone x for month m.

The short-term market Voltage Support charges for Settlement Period t payable by Scheduling Coordinator j will be calculated as follows:

$$VSSTCharge_{jt} = VSSTRate_t * QChargeVS_{jt}$$

where $VSSTCharge_{jt}$ is the amount payable by Scheduling Coordinator j for short-term market Voltage Support for Settlement Period t.

$VSSTRate_t$ is the short-term market Voltage Support user rate for Settlement Period t. The monthly long-term Voltage Support contract charge for month m payable by Scheduling Coordinator j will be calculated as follows:

$$VSLTCharge_m = VSLTRate_m * \sum_m QChargeVS_{jt}$$

where $VSLTCharge_m$ is the amount payable by Scheduling Coordinator j for long-term Voltage Support for month m.

$VSLTRate_m$ is the monthly long-term Voltage Support contract user rate charged by the ISO to Scheduling Coordinators for month m.

8.12.5 Black Start.

$QChargeBlackstart_{jt}$ = charging quantity for Black Start for Scheduling Coordinator j for Settlement Period t equal to the total metered Demand (excluding exports to neighboring Control Areas and metered Demand of a MSS) by Scheduling Coordinator j for Settlement Period t.

The Black Start Energy payment user rate for Settlement Period t will be calculated as follows:

$$BSRate_t = \frac{\sum_{i,j} BSEn_{ijt}}{\sum_j QChargeBlackstart_{jt}}$$

where $BSEn_{ijt}$ is the ISO payment to Scheduling Coordinator j for owner of Reliability Must-Run Unit (or to Black Start Generator j, as the case may be) for Generating Unit i providing Black Start Energy in Settlement Period t.

The Black Start Energy user charge for Settlement Period t for Scheduling Coordinator j will be calculated as follows:

$$BSCharge_{jt} = BSRate_t * QChargeBlackStart_{jt}$$

8.13 Temporary Changes To Ancillary Services Penalties.

8.13.1 Application and Termination.

The temporary change, respecting Ancillary Services penalties, set out in Section 8.13.2 shall continue in effect until such time as the Chief Executive Officer of the ISO issues a Notice of Full-Scale Operations, posted on the ISO Internet "Home Page", at <http://www.ISO.com>, or such other Internet address as the ISO may publish from time to time, specifying the date on which this Section 8.13 shall cease to apply, which date shall be not less than seven (7) days after the Notice of Full-Scale Operations is issued.

8.13.2 For so long as this Section 8.13.2 remains in effect, Scheduling Coordinators shall not be liable for the penalties specified in Section 8.10.2 of the ISO Tariff if, as a result of limitations associated with the ISO's Congestion Management software, the scheduled output of the resource from which the Scheduling Coordinator has committed to provide an Ancillary Service is adjusted by the ISO to a level

that conflicts with the Scheduling Coordinator's Ancillary Service capacity commitments, thereby resulting in a failed availability test.

8.14 Temporary Rule Limiting Adjustment Bids Applicable To Dispatchable Loads And Exports.

8.14.1 Application and Termination.

The temporary change limiting Adjustment Bids for Dispatchable Loads and exports set out in Section 8.14.2 shall continue in effect until such time as the Chief Executive Officer of the ISO posts a notice ("Notice of Full-Scale Operations"), on the ISO Home Page specifying the date on which this Section 8.14 shall cease to apply, which date shall not be less than seven (7) days after the Notice of Full-Scale Operations is posted.

8.14.2 For so long as this Section 8.14.2 remains in effect, Scheduling Coordinators shall continue to be allowed to specify Adjustment Bids for Dispatchable Loads and exports, conditioned on the rule that the last segment of the Adjustment Bid (i.e., the maximum MW value) must equal the preferred MW operating point specified for the Dispatchable Load or export.

9. OUTAGES.

9.1 Coordination and Approval for Outages.

The ISO shall have authority to coordinate and approve Outages and returns to service of all facilities comprised in the ISO Controlled Grid and Reliability Must-Run Units in accordance with Section 9.3. The ISO will coordinate and approve Maintenance Outages and coordinate responses to Forced Outages of all transmission facilities in the ISO Controlled Grid and Reliability Must-Run Units in accordance with this Section 9. Any scheduled Outages that are cancelled by ISO real-time operations due to system requirements must be rescheduled with the ISO Outage Coordination Department in accordance with Section 9.3.

9.2 Responsibility for Authorized Work on Facilities.

The ISO shall have authority to approve requests by Participating TOs to work on all energized transmission equipment under the Operational Control of the ISO.

9.3 Coordination of Outages and Maintenance.

9.3.1 ISO Outage Coordination Office.

The ISO Outage Coordination Office shall be established by the ISO and shall coordinate and approve Maintenance Outages of: (i) all facilities that comprise the ISO Controlled Grid and (ii) Participating Generators. The ISO shall additionally coordinate and approve Outages required for new construction and for work on de-energized and live transmission facilities (e.g., relay maintenance or insulator washing) and associated equipment. The ISO Outage Coordination Office will be operational Monday through Friday, except holidays. The Outage Coordination Office is located in Folsom. Each office and the areas of responsibility of that office are detailed in the most recent version of the applicable ISO Operating Procedures, which are posted on the ISO Home Page.

9.3.1A Coordinating Maintenance Outages of UDC Facilities.

Each UDC and the Participating TO with which it is interconnected shall coordinate their Outage requirements that will have an effect on their transmission interconnection prior to the submission by that Participating TO of its Maintenance Outage requirements under Section 9.3.

9.3.1.1 Coordinating Maintenance Outages of CDWR-SWP Participating Generating Units.

The provisions of Section 9.3 shall apply to CDWR-SWP Participating Generating Units. The submission by CDWR-SWP of an Outage schedule, Outage request, or request to change or cancel an Approved Maintenance Outage, and the ISO's treatment of Outage schedules and requests relating to CDWR-SWP Participating Generating Units, shall be in accordance with Section 9.3, except as otherwise provided in Section 9.3.1.1.1.

9.3.1.1.1 Coordinating Maintenance Outages of CDWR-SWP

a. In each Outage schedule, Outage request, and request to change or cancel an Approved Maintenance Outage that CDWR-SWP submits to the ISO for a CDWR-SWP Participating Generating Unit, CDWR-SWP will state whether CDWR-SWP has determined that the proposed maintenance work, and/or the timing of the Outage, is necessary in order for CDWR-SWP to:

- i. Comply with various federal and state legal and regulatory requirements that govern stream flow, water temperature, water quality and quantity, flood control space, after-bay, reservoir, or lake elevation, and other environmental and wildlife constraints (“CDWR-SWP Statutory Compliance Outage”); or
- ii. Maintain reliable operations of critical water infrastructure and not impair its ability to satisfy water delivery or conservation requirements (“CDWR-SWP Water System Reliability Outage”).

b. CDWR-SWP will identify each CDWR-SWP Statutory Compliance or Water System Reliability Outage by designating the Outage with an appropriate cause code in the Outage schedule, Outage request, or request to change or cancel an Approved Maintenance Outage and will provide a description of the requirement or constraint. If the designation of an Outage changes, or the Outage no longer meets the criteria of Section 9.3.1.1.1(a)(i) or (ii), CDWR-SWP will notify the ISO about this change in status as soon as practical but no more than one business day after it occurs.

c. The ISO will not deny, cancel, or reschedule a CDWR-SWP Statutory Compliance or Water System Reliability Outage that CDWR-SWP submits to the ISO in an Outage schedule, Outage request, or request to change or cancel an Approved Maintenance Outage, provided that the Outage request is timely, designates the Outage as a CDWR-SWP Statutory Compliance or Water System Reliability Outage by an appropriate cause code and includes a description of the requirement or constraint.

d. The ISO may contact CDWR-SWP to inquire whether the timing of a CDWR-SWP Statutory Compliance or Water System Reliability Outage can be changed. CDWR-SWP may agree to the change or, after making best efforts to accommodate the change, may notify the ISO that the change is not feasible as determined by CDWR-SWP in its sole discretion due to the described requirement or constraint. In the event that CDWR-SWP determines that changing the timing of the Outage is not feasible due to the described requirement or constraint, the ISO will not deny, cancel, or reschedule that CDWR-SWP Statutory Compliance or Water System Reliability Outage.

e. The ISO will process any Outage that CDWR-SWP submits in an Outage schedule, Outage request, or request to change or cancel an Approved Maintenance Outage, that is not timely, does not contain a cause code identifying the Outage as a CDWR-SWP Statutory Compliance or Water System Reliability Outage or does not include a description of the requirement or constraint, under the otherwise applicable provisions of ISO Tariff Section 9.3 and ISO Operating Procedures.

9.3.2 Requirement for Approval.

An Operator shall not take: (i) facilities that comprise the ISO Controlled Grid or (ii) Participating Generators out of service for the purposes of planned maintenance or for new construction or other work except as approved by the ISO Outage Coordination Office. The information relating to each Maintenance Outage submitted by a Participating Generator in accordance with Section 9.3.5 or by a Participating TO in accordance with Section 9.3.5 constitutes a request for a long-range Maintenance Outage and is not considered an Approved Maintenance Outage until the ISO has notified the Participating Generator of such approval pursuant to Section 9.3.6 or the Participating TO pursuant to Section 9.3.6.

9.3.3 Requests for Outages in Real-Time Operation.

Requests for Outages of: (i) facilities that comprise the ISO Controlled Grid or (ii) Participating Generators in real-time operation shall be made by the Operator to the ISO Control Center. The ISO will not approve any Outage request made within seventy-two (72) hours of the requested Outage start time unless: (i) the requested Outage could not have been reasonably foreseen and scheduled through the Outage coordination process provided in Section 9.3; and (ii) the requested Outage will not compromise ISO Controlled Grid reliability.

9.3.4 Single Point of Contact.

Requests for approvals and coordination of all Maintenance Outages (consistent with Section 9.3.1) will be through a single point of contact between the ISO Outage Coordination Office and each Operator. The Operator shall provide in its initial request and specify from time to time the identification of the single point of contact along with primary and alternate means of communication pursuant to the detailed procedures referred to in Section 9.3.6.

9.3.5 Method of Communications.

The primary method of communication from an Operator to the ISO with regard to maintenance and outage planning will be as described in the Operating Procedure on the ISO Home Page. Emergency capabilities, to be used only as a back-up if the primary communication method is unavailable, will include:

- (a) voice;
- (b) fax; and
- (c) electronic (E-mail, FTP file, etc.).

9.3.5.1 Confirmation.

When fax or electronic communication is utilized, confirmation from the ISO must be received by the Operator to validate the receipt of the request.

9.3.5.2 Communication of Approval or Rejection.

The ISO shall use the same methods in communicating the approval or rejection of an Outage request or approval of a request to change an Approved Maintenance Outage to the relevant Operator.

9.3.5.2A Information regarding planned outages for resources providing Regulatory Must-Take Generation shall be provided to the ISO Outage Coordination Office by the Participating TO or UDC having an existing contract with such resource or by a Participating Generator. Information provided will be that obtained by the Participating TO, UDC or a Participating Generator pursuant to the terms of the existing agreement with the Regulatory Must-Take Generation resource or as requested by the ISO. Scheduling and approvals of Maintenance Outages for resources providing Regulatory Must-Take Generation shall continue to be coordinated as detailed in the applicable contract with the Participating TO or UDC, provided the Regulatory Must-Take Generator has not executed a Participating Generator Agreement. If the Regulatory Must-Take Generator has executed a Participating Generator Agreement, it shall comply with Section 9.3.5 and other provisions applicable to Participating Generators.

9.3.6 Maintenance Outage Planning.

Each Operator shall, by not later than October 15 each year, provide the ISO with a proposed schedule of all Maintenance Outages it wishes to undertake in the following year. The proposed schedule shall include all of the Operator's transmission facilities that comprise the ISO Controlled Grid and Participating Generators (including its Reliability Must-Run Units). In the case of a Participating TO's transmission facilities, that proposed schedule shall be developed in consultation with the UDCs interconnected with that Participating TO's system and shall take account of each UDC's planned maintenance requirements. The nature of the information to be provided and the detailed Maintenance Outage Planning Procedure shall be established by the ISO. This information shall include:

The following information is required for each Generating Unit of a Participating Generator:

- (a) the Generating Unit name and Location Code;
- (b) the MW capacity unavailable;
- (c) the scheduled start and finish date for each Outage; and
- (d) where there is a possibility of flexibility, the earliest start date and the latest finish date, along with the actual duration of the Outage once it commences.

The following information is required for each transmission facility:

- (a) the identification of the facility and location;
- (b) the nature of the proposed Maintenance Outage;
- (c) the preferred start and finish date for each Maintenance Outage; and
- (d) where there is a possibility of flexibility, the earliest start date and the latest finish date, along with the actual duration of the Outage once it commences.

Either the ISO, pursuant to Section 9.3.7, or an Operator, subject to Section 9.3.6.10, may at any time request a change to an Approved Maintenance Outage. An Operator may, upon seventy-two (72) hours

advance notice, schedule with the ISO Outage Coordination Office a Maintenance Outage on its system, subject to the conditions of Sections 9.3.6.4A, 9.3.6.7, and 9.3.6.8.

9.3.6.1 Quarterly Updates.

9.3.6.1A Each Participating Generator will provide the ISO with quarterly updates of its long-range Outage schedule referred to in Section 9.3.6 for Generating Units and System Units by the close of business on the fifteenth (15th) day of each January, April, and July. These updates must identify known changes to any previously planned Generating Unit Outages and any additional Outages anticipated over the next twelve months from the time of this report. In this report, each Participating Generator must include all known planned Outages for the following twelve months.

9.3.6.1B Each Participating TO will provide the ISO with quarterly updates of the data provided under 9.3.6 by close of business on the fifteenth (15th) day of each January, April, and July. These updates must identify known changes to any previously planned ISO Controlled Grid facility Maintenance Outages and any additional Outages anticipated over the next twelve months from the time of the report. As part of this update, each Participating TO must include all known planned Outages for the following twelve months.

9.3.6.2 90 Day Look Ahead.

In addition to changes made at quarterly Outage submittals, each Participating Generator shall notify the ISO in writing of any known changes to a Generating Unit or System Unit Outage scheduled to occur within the next 90 days and may submit changes to its planned Maintenance Outage schedule at any time. Participating Generators must obtain the approval of the ISO Outage Coordination Office in accordance with Section 9 of this ISO Tariff. Such approval may be withheld only for reasons of System Reliability or security.

9.3.6.3 72 Hour Ahead.

An Operator may, upon seventy-two (72) hours advance notice (or within the notice period in the Operating Procedures posted on the ISO Home Page), schedule with the ISO Outage Coordination Office a Maintenance Outage on its system, subject to the conditions of Sections 9.3.6.4A, 9.3.6.7 and 9.3.6.8.

9.3.6.4 Changes to Planned Maintenance Outages.

A Participating TO may submit changes to its planned Maintenance Outage information at any time, provided, however, that if the Participating TO cancels an Approved Maintenance Outage after 5:00 a.m. of the day prior to the day upon which the Outage is scheduled to commence and the ISO determines that the change was not required to preserve System Reliability, the ISO may disregard the availability of the affected facilities in determining the availability of transmission capacity in the Day-Ahead Market. The ISO will, however, notify Market Participants and reflect the availability of transmission capacity in the Hour-Ahead Market as promptly as practicable.

9.3.6.4A The ISO Outage Coordination Office shall evaluate whether the requested Maintenance Outage or change to an Approved Maintenance Outage is likely to have a detrimental effect on the efficient use and reliable operation of the ISO Controlled Grid or the facilities of a Connected Entity. The ISO may request additional information or seek clarification from Participating Generators or Participating TOs of the information submitted in relation to a planned Generating Unit and System Unit Outage or a planned Maintenance Outage. This information may be used to assist the ISO in prioritizing conflicting requests for Outages.

9.3.6.4B ISO Analysis of Generating Unit Outage Plans

9.3.6.4B.1 Calculation of Aggregate Generating Capacity

The ISO will use the long-range Generating Unit or System Unit Outage schedule referenced in 9.3.6 and, as appropriate, additional approved Outage requests scheduled to start within 90 days, to calculate the aggregate Generation capacity projected to be available in the following time frames:

- (a) on an annual and quarterly basis, the ISO will calculate the aggregate weekly peak Generation capacity projected to be available during each week of the following year and quarter, respectively; and

(b) on a monthly basis, the ISO will calculate the aggregate daily peak Generation capacity projected to be available during the month.

9.3.6.5 Withdrawal or Modification of Request.

The Operator of a Participating Generator or a Participating TO's Operator may withdraw a request at any time prior to actual commencement of the Outage. The Operator of a Participating Generator or Participating TO's Operator may modify a request at any time prior to receipt of any acceptance or rejection notice from the ISO Outage Coordination Office or pursuant to Sections 9.3.8.1, 9.3.8.2 and 9.3.8.3, but the ISO Outage Coordination Office shall have the right to reject such modified request for reasons of System Reliability, system security or market impact, because of the complexity of the modifications proposed, or due to insufficient time to assess the impact of such modifications.

9.3.6.6 Each Participating Generator or Participating TO which has scheduled a planned Maintenance Outage pursuant to Section 9.3.4 must schedule and receive approval of the Outage from the ISO Outage Coordination Office prior to initiating the Approved Maintenance Outage. The ISO Outage Coordination Office will review the Maintenance Outages to determine if any one or a combination of Maintenance Outage requests relating to ISO Controlled Grid facilities, Generating Units or System Units may cause the ISO to violate the Applicable Reliability Criteria. This review will take consideration of factors including, but not limited to, the following:

- (a) forecast peak Demand conditions;
- (b) other Maintenance Outages, previously Approved Maintenance Outages, and anticipated Generating Unit Outages;
- (c) potential to cause Congestion;
- (d) impacts on the transfer capability of Interconnections; and
- (e) impacts on the market.

9.3.6.7 The ISO Outage Coordinator Office shall acknowledge receipt of each request to confirm or approve a Maintenance Outage for a Generation Unit, System Unit, or Aggregated Unit. Where the ISO Outage Coordination Office reasonably determines that the requested Maintenance Outage or the requested change to an Approved Maintenance Outage, when evaluated together with existing Approved Maintenance Outages, is not likely to have a detrimental effect on the efficient use and reliable operation of the ISO Controlled Grid, the ISO shall authorize the Maintenance Outage or change to the Approved Maintenance Outage, and shall so notify the requesting Operator and other entities who may be directly affected.

9.3.6.8 Where, in the reasonable opinion of the ISO Outage Coordination Office, the requested Maintenance Outage or requested change to an Approved Maintenance Outage is likely to have a detrimental effect on the efficient use and reliable operation of the ISO Controlled Grid, the ISO Outage Coordination Office may reject the requested Maintenance Outage or requested change to Approved Maintenance Outage. If in the ISO's determination, any of the Maintenance Outages would cause the ISO to violate the Applicable Reliability Criteria, the ISO will notify the relevant Operator, and the Operator will then revise the proposed Maintenance Outage and inform the ISO of the proposed changes. The ISO Outage Coordination Office shall, in a rejection notice, identify the ISO's reliability, security and market concerns which prompt the rejection and suggest possible remedies or schedule revisions which might mitigate any such concerns. The ISO Outage Coordination Office may provide each Operator in writing with any suggested amendments to those Maintenance Outage requests rejected by the ISO Outage Coordination Office. Any such suggested amendments will be considered as an ISO maintenance request and will be approved in accordance with the process set forth in Section 9.3.7 of the ISO Tariff. The determination of the ISO Outage Coordination Office shall be final and binding on the Operator. If, within fourteen (14) days of having made its determination, the Operator requests the ISO Outage Coordination Office to provide reasons for its determination, it shall do so as soon as is reasonably practicable. The ISO will give reasons for informational purposes only and without affecting in any way the finality or validity of the determination.

9.3.6.9 Failure to Meet Requirements.

Any request to consider maintenance that does not meet the notification requirements contained in Sections 9.3.8.2 and 9.3.8.3 will be rejected without further consideration, unless Section 9.3.10 applies.

9.3.6.10 In the event an Operator of facilities forming part of the ISO Controlled Grid cancels an Approved Maintenance Outage after 5:00 a.m. of the day prior to the day upon which the Outage is scheduled to commence and the ISO determines that the change was not required to preserve System Reliability, the ISO may disregard the availability of the affected facilities in determining the availability of transmission capacity in the Day-Ahead Market, provided, however, that the ISO will, as promptly as practicable, notify Market Participants and reflect the availability of the affected facilities in determining the availability of transmission capacity in the Hour-Ahead Market.

9.3.7 Maintenance Outage Requests by the ISO.

The ISO Outage Coordination Office may at any time request a Maintenance Outage or a change to an Approved Maintenance Outage from an Operator if, in the opinion of the ISO Outage Coordination Office, the requested Maintenance Outage or change is required to secure the efficient use and reliable operation of the ISO Controlled Grid. In addition, the ISO Outage Coordination Office may, by providing notice no later than 5:00 a.m. of the day prior to the day upon which the Outage is scheduled to commence, direct the Operator to cancel an Approved Maintenance Outage, when necessary to preserve or maintain System Reliability or, with respect to Reliability Must-Run Units or facilities that form part of the ISO Controlled Grid, to avoid unduly significant market impacts that would arise if the Outage were to proceed as scheduled. The Operator, acting in accordance with Good Utility Practice, shall comply with the ISO's direction and the provisions of Sections 9.3.7.1 and 9.3.7.2 shall apply. The ISO shall give notice of any such direction to Market Participants prior to the deadline for submission of initial Preferred Day-Ahead Schedules for the day on which the Outage was to have commenced. For purposes of this section and Section 9.3.3, an "unduly significant market impact" means an unplanned event or circumstance (e.g., unseasonable weather, a Forced Outage of a facility, or other occurrence) that adversely affects the competitive nature and efficient workings of the ISO Markets, and is of such severity

that a prudent Operator would not have scheduled a Maintenance Outage of its facility if the unplanned event or circumstance could have been anticipated.

9.3.7.1 The Operator may: (1) refuse the request; (2) agree to the request; or (3) agree to the request subject to specific conditions. The Operator, acting in accordance with Good Utility Practice, shall make every effort to comply with requests by the ISO Outage Coordination Office. In the event that the Operator refuses the ISO's request, it shall provide to the ISO Outage Coordination Office written justification for its position within seventy-two (72) hours.

9.3.7.2 In response the ISO Outage Coordination Office may: (1) overrule any refusal of a Maintenance Outage or a change to an Approved Maintenance Outage by an Operator, in which case the ISO Outage Coordination Office determination shall be final; (2) accept any changes or conditions proposed by the Operator, in which case the Maintenance Outage request or the request to change an Approved Maintenance Outage shall be deemed to be amended accordingly; or (3) reject the change or condition, in which case the ISO Outage Coordination Office and the Operator shall determine if acceptable alternative conditions or changes can be agreed. If the Operator and the ISO Outage Coordination Office cannot agree on acceptable alternative conditions or changes to the ISO Outage Coordination Office's request for a Maintenance Outage or change to an Approved Maintenance Outage, the ISO Outage Coordination Office determination shall be final. If the Operator and the ISO Outage Coordination Office cannot agree on acceptable alternative conditions or changes to the ISO Outage Coordination Office's request for a Maintenance Outage or change to an Approved Maintenance Outage, the ISO may notify the FERC of the dispute and take any other steps that are within its authority to maintain the reliability of the ISO Controlled Grid.

9.3.7.3 The ISO will compensate the applicable Participating TO or Participating Generator for any direct and verifiable costs that such Participating TO or Participating Generator incurs as a result of the ISO's cancellation of an Approved Maintenance Outage pursuant to this Section 9.3.7. For purposes of this section, direct costs include verifiable labor and equipment rental costs that have been incurred by the applicable Participating TO or Participating Generator solely as a result of the ISO's cancellation of the Approved Maintenance Outage. Each Participating TO or Participating Generator must make a

reasonable effort to avoid incurring any such direct costs through such measures as, but not limited to, the prompt cancellation of all contractual arrangements with third parties related to the Approved Maintenance Outage.

9.3.7.4 The amount used to compensate each applicable Participating TO and Participating Generator, as described in Section 9.3.7.3, shall be charged to the Scheduling Coordinators in proportion to their metered Demand (including exports) during the Settlement Period(s) of the originally scheduled Outage.

9.3.8 The ISO Outage Coordination Office shall provide notice to the Operator of the approval or disapproval of any requested Maintenance Outage. Additionally, the ISO Outage Coordination Office shall notify any Connected Entity that may in the reasonable opinion of the ISO Outage Coordination Office be directly affected by an Approved Maintenance Outage. The content of and procedures for such notice shall be established by the ISO.

9.3.8.1 Data Required.

The Operator of a Participating Generator owned or controlled by a Participating Generator shall submit to the ISO pursuant to Sections 9.3.4 and 9.3.5.2A its request to confirm the schedule of a planned Maintenance Outage or to change the schedule of a planned Maintenance Outage. Such request must be made to the ISO Outage Coordination Office by no later than 11:30 am three (3) working days prior to the starting date of the proposed Outage (or as specified on the ISO Home Page). Likewise, all Participating TOs shall submit a formal request to confirm or change an Approved Maintenance Outage with respect to any ISO Controlled Grid facility to the ISO Outage Coordination Office in accordance with Sections 9.3.8.2 and 9.3.8.3.

Such schedule confirmation request shall specify the following:

- (a) the Generating Unit or System Unit name and Location Code, or the identification of the transmission system element(s) to be maintained including location;
- (b) the nature of the maintenance to be performed;

- (c) the date and time the Outage is to begin;
- (d) the date and time the Outage is to be completed;
- (e) the time required to terminate the Outage and restore the Generating Unit to normal capacity or the transmission system to normal operation;
- (f) identification of primary and alternate telephone numbers for the Operator's single point of contact; and
- (g) in the case of a request for a change to an Approved Maintenance Outage, the date and time of the original Approved Maintenance Outage.

9.3.8.2 Three (3) Day Prior Notification.

Any request to confirm an Approved Maintenance Outage that may affect the transfer capability of any part of the ISO Controlled Grid must be submitted no later than 11:30 am at least three (3) working days prior to the starting date of the Approved Maintenance Outage (or as posted on the ISO Home Page). This Section applies to facilities as described on the ISO Home Page.

Failure to submit a request for an Outage by the proper time may mean a delay in approval from the ISO or may cause that Outage to be designated as a Forced Outage based on the nearness of the request to the requested Outage date.

9.3.8.3 One (1) Day Prior Notification.

Any request to confirm or change the Schedule for an Approved Maintenance Outage requiring only one day notice (as detailed on the ISO Home Page) must be submitted no later than 11:30 am at least one (1) day prior to the starting date of the Outage (or as specified on the ISO Home Page). Failure to submit a request for an Outage by the proper time may mean a delay in approval from the ISO or may cause that Outage to be designated as a Forced Outage.

9.3.8.4 Priority of Outage Requests. Outage requests which are listed in the long-range maintenance schedules submitted to and approved by the ISO will be given a priority in the scheduling and approval of Outage requests over those which have not been listed.

9.3.8.5 Delay. The ISO Outage Coordination Office may delay its approval of an Approved Maintenance Outage schedule if sufficient or complete information is not received by the ISO Outage Coordination Office within the time frames provided in Sections 9.3.8.2 and 9.3.8.3.

9.3.9 Final Approval, Delay and Withholding.

On the day on which an Approved Maintenance Outage is scheduled to commence, the Operator shall contact the ISO Control Center for final approval of the Maintenance Outage. No Maintenance Outage shall commence without such final approval (including the time of release, in hours and minutes) being obtained from the ISO Control Center whose decision shall be final. The ISO Outage Coordination Office may delay its approval of a scheduled Maintenance Outage for a Participating Generator if sufficient or complete information is not received by the ISO Outage Coordination Office within the time frames set forth in Section 9.3.8.1. The ISO Control Center shall have the authority to withhold a Final Approval for an Approved Maintenance Outage for reasons of System Reliability, security or system status of the ISO Controlled Grid or market impact. The ISO Control Center shall immediately notify the relevant Operator of its intention to withhold the Final Approval. The Generator Maintenance Outage or ISO Controlled Grid facility Maintenance Outage will then be rescheduled pursuant to this ISO Tariff.

9.3.10 Forced Outages.

9.3.10.1 Coordination of all Forced Outages (consistent with Sections 9.3.4 and 9.3.5.2A) will be through the single point of contact between the Operator and the ISO Control Center.

9.3.10.1A Each Participating TO shall report any change or potential change in equipment status of the Participating TO's transmission assets turned over to the control of the ISO or in equipment that affects transmission assets turned over to the control of the ISO immediately upon discovery to the ISO (this will include line and station equipment, line protection, Remedial Action Schemes and communication problems, etc.). Each Participating TO shall also keep the ISO immediately informed upon discovery as to any change or potential change in the Participating TO's transmission system that could affect the reliability of the ISO Controlled Grid. This would include, but is not limited to, adverse weather conditions, fires, bomb threats, system failures, etc.

9.3.10.2 Any Operator, upon identification of a situation likely to result in a Forced Outage within the next twenty-four (24) hours unless immediate corrective action is taken, where such action requires the removing from service or reducing the maximum output capability of a Generating Unit by 10 MW or more from the value most recently recorded in SLIC, or removing a transmission facility from service, shall communicate directly with the ISO Control Center. All such notifications of Forced Outages shall be communicated to the ISO Control Center with as much notice as possible in order that the necessary security analysis and ISO Controlled Grid assessments may be performed. Any Operator, upon identification of a situation likely to result in a Forced Outage but of a nature not requiring a removal from service until some time more than twenty-four (24) hours in the future will be subject to the provisions of Section 9 of this ISO Tariff with respect to any necessary Outage except the requirements imposing time limits for notification will be waived and the request will be expedited by the ISO provided notice is given as soon as possible.

9.3.10.2.1 If prior notice of a Forced Outage cannot be given, the Operator of a Generating Unit is required to notify the ISO within 60 minutes after discovering any change in the maximum output capability of at least 10 MW or 5% of the value registered in the Master File, whichever is greater, from the value registered in SLIC that lasts for 15 minutes or longer.

9.3.10.3 The ISO Control Center shall coordinate any operational changes necessary to accommodate a Forced Outage and Market Participants shall comply with the ISO's instructions given for that purpose.

9.3.10.4 All Forced Outages shall be communicated by the ISO Control Center to Operators likely to be affected by the Outage using the same procedures adopted for Maintenance Outage coordination procedures.

9.3.10.5 With respect to Forced Outages of Generating Units that result in a reduction in maximum output capability that lasts 15 minutes or longer of 40 MW or more below the value registered in the Master File and 10% of the value registered in the Master File, the Operator shall provide to the ISO an explanation of the Forced Outage and the estimated return time, within two (2) Business Days *after the Operator initially notifies the ISO pursuant to Section 9.3.10.2.1 of the change in maximum output capability. The explanation shall include a description of the equipment failure or other cause and a description of all remedial actions taken by the Operator.* Upon request of the ISO, Operators, and where applicable, Eligible Customers, Scheduling Coordinators, UDCs and MSSs promptly shall provide information requested by the ISO to enable the ISO to review the changes made to the maximum output capability or to provide further information relative to the explanation of the Forced Outages submitted by the Operator and to prepare reports on Forced Outages. If the ISO determines that any Forced Outage may have been the result of gaming or other questionable behavior by the Operator, the ISO shall submit a report describing the basis for its determination to the FERC. The ISO shall consider the following factors when evaluating the Forced Outage

was the result of gaming or other questionable behavior by the Operator: 1) if the Forced Outage coincided with certain market conditions such that the Forced Outage may have influenced market prices or the cost of payments associated with out-of-sequence dispatches, out-of-market dispatches, or Real Time Market dispatches above the Marginal Proxy Clearing Price or Non-Emergency Clearing Price Limit, as applicable; 2) if the Forced Outage coincided with a change in the bids submitted for any units or resources controlled by the Operator or the Operator's Scheduling Coordinator; 3) if the ISO had recently rejected a request for an Outage for, or to shut down, the Generating Unit experiencing the Forced Outage; 4) if the timing or content of the notice of the Forced Outage provided to the ISO was inconsistent with subsequent reports of or the actual cause of the Outage; 5) if the Forced Outage or the duration of the Forced Outage was inconsistent with the history or past performance of that Generating Unit or similar Generating Units; 6) if the Forced Outage created or exacerbated Congestion; 7) if the Forced Outage was extended with little or no notice; 8) if the Operator had other alternatives to resolve the problems leading to the Forced Outage; 9) if the Operator took reasonable action to minimize the duration of the Forced Outage; or 10) if the Operator failed to provide the ISO an explanation of the Forced Outage within two (2) Business Days or failed to provide any additional information or access to the generating facility requested by the ISO within a reasonable time.

9.3.10.6 Other Control Areas.

The ISO Outage Coordination Office shall make all reasonable efforts to coordinate Outages involving other Control Areas or affecting an intertie, import or export capability not under the Operational Control of the ISO to the extent that they may affect the reliability of the ISO Controlled Grid.

9.4 Outage Coordination For New Facilities.

9.4.1 Coordination by ISO. The procedure to energize and place in service any new or relocated piece of equipment, connected to the ISO Controlled Grid, must be set out by the Operator or Connected Entity in a written procedure and coordinated by the ISO Outage Coordination Office.

9.4.2 Types of Work Requiring Coordination.

The types of work which the ISO will coordinate includes any new addition, replacement or modification to the ISO Controlled Grid, including:

- (a) transmission lines forming part of the ISO Controlled Grid;
- (b) equipment including circuit breakers, transformers, disconnects, reactive devices, wave traps, forming part of the ISO Controlled Grid;
- (c) Generating Unit interconnections; and
- (d) protection and control schemes, including RAS, SCADA, EMS, or AGC.

9.4.3 Uncomplicated Work.

When line rearrangements and/or station equipment work is uncomplicated and easily understood, the ISO Outage Coordination Office may determine that the work can be accomplished using Outages approved in accordance with Section 9.3.6. The ISO Outage Coordination Office will make this determination in coordination with the respective requesting Operator or Connected Entity.

9.4.4 Special Procedures for More Complex Work.

9.4.4.1 Responsibility for Preparation.

In cases to which 9.4.3 does not apply, it is the responsibility of the requesting Operator or Connected Entity to prepare a written procedure to enable the ISO to approve Outages in a manner that enables the necessary work to proceed. The ISO Outage Coordination Office must approve the procedure.

9.4.4.2 Information to be Provided to the ISO.

The written procedure must be received by the ISO Outage Coordination Office a minimum of four (4) weeks prior to the start of procedure. Adequate drawings will be attached to the procedure to help clarify the work being performed and the Outages that will be required to complete the work must be specified. The procedure shall include all of the information referred to on the ISO Home Page.

9.4.4.3 Approval of the Procedure.

Upon receipt of the procedure and drawings referred to in Section 9.4.4.2, the ISO Outage Coordination Office will review the procedure and notify the Operator or Connected Entity of any required modifications. The ISO Outage Coordination Office may, at its discretion, require changes to and more detail to be inserted in the procedure. The requesting Operator or Connected Entity will consult with other entities likely to be affected and will revise the procedure, following any necessary or appropriate discussions with the ISO to reflect the requirements of the ISO. Following the ISO approval, an approved copy of the procedure will then be transmitted to the Operator or Connected Entity and the other entities likely to be affected.

9.4.4.4 Changes to Procedure.

Once the procedure is approved by the ISO Outage Coordination Office any modifications to the procedure will require the requesting Operator or Connected Entity to notify the ISO Outage Coordination Office with as much lead time as possible of the recommended changes. The modified procedure will then have to be approved by the ISO Outage Coordination Office in accordance with Section 9.4.4.2 and 9.4.4.3.

9.4.4.5 Approval of Work Requiring Coordination.

No work can begin pursuant to any approved procedure unless approved by the ISO Outage Coordination Office.

9.5 Records.

The ISO and all Operators shall develop procedures to keep a record of approved Maintenance Outages as they are implemented and to report the completion of approved Maintenance Outages. Such records are available for inspection by Operators and Connected Entities at the ISO Outage Coordination Office. Only those records pertaining to the equipment or facilities owned by the relevant Operator or Connected Entity will be made available for inspection at the ISO Outage Coordination Office, and such records will only be made available provided notice is given in writing to the ISO fifteen (15) days in advance of the requested inspection date.

9.6 Facility Owner.

The Facility Owner shall remain solely and directly responsible for the performance of all maintenance work, whether on energized or de-energized facilities, including all activities related to providing a safe working environment.

10 METERING.

10.1 Applicability.

Unless otherwise expressly stated to the contrary, the requirements set forth in these Sections 10.1 to 10.5 inclusive apply only to ISO Metered Entities. If an ISO Metered Entity is also a Scheduling Coordinator, it shall be treated as an ISO Metered Entity for the purposes of Section 10 of the ISO Tariff. Such an ISO Metered Entity will not be required to enter into a Scheduling Coordinator Meter Service Agreement unless it represents any metered entities other than itself. A Scheduling Coordinator Meter Service Agreement entered into by an ISO Metered Entity shall only apply to those metered entities that the ISO Metered Entity represents; the Scheduling Coordinator Meter Service Agreement shall not apply to the ISO Metered Entity other than in its capacity as Scheduling Coordinator for those metered entities.

10.1.1 Role of the ISO.

The ISO is responsible for establishing and maintaining the revenue meter data acquisition and processing system (MDAS). MDAS will acquire revenue quality meter data for use in the ISO's Settlement and billing process. The ISO is also responsible for:

- (a) setting standards and procedures for the registration, certification, auditing, testing and maintenance of revenue quality meters and meter data servers; and
- (b) for establishing procedures for the collection, security, validation and estimation of Meter Data for metered entities that are subject to the ISO Tariff.

10.1.3 Netting.

10.1.3.1 Permitted Netting.

ISO Metered Entities may, when providing Meter Data to the ISO, net values for Generating Unit output and auxiliary Load equipment electrically connected to that Generating Unit at the same point provided that the Generating Unit is on-line and is producing sufficient output to serve all of that auxiliary Load equipment. For example, where a Generating Unit's auxiliary load equipment is served via a distribution line that is separate from the switchyard to which the Generating Unit is connected, that Generating Unit and auxiliary load equipment will not be considered to be electrically connected at the same point.

10.1.3.2 Prohibited Netting.

ISO Metered Entities may not net values for Generating Unit output and Load. ISO Metered Entities that serve third party Load connected to a Generating Unit's auxiliary system must add that third party Load to the Generating Unit's output. The ISO Metered Entity may add that third party Load to the Generating Unit's output either by means of a hard wire local meter connection between the metering systems of the third party Load and the Generating Unit or by requesting the ISO to use MDAS to perform the addition. The ISO Metered Entity must ensure that the third party Load has Metering Facilities that meet the standards referred to in the ISO Tariff.

10.1.5 Access to Meter Data.

The ISO has complete authority over all rights of access to (and has authority to deny access to) the ISO's revenue meter data acquisition and processing system including servers (where used), interface equipment, and software needed to collect the relevant information for Settlement, billing and related purposes. Each Market Participant acknowledges this ISO authority as a condition of ISO Controlled Grid service and participation. For ISO Metered Entities, authority over the sealing of meters, and all related metering facilities, shall reside solely with the ISO for all ISO designated Meter Points, regardless of any remote electronic access that an ISO Metered Entity or its Scheduling Coordinator may have provided to third parties, except as otherwise may be required by law, FERC, any Local Regulatory Authority or other provision of this ISO Tariff. Meter Data supplied by an ISO Metered Entity shall be

made available by the ISO to the Scheduling Coordinator representing such ISO Metered Entity and the other authorized users identified in its Meter Service agreement, but shall not be disclosed to any other third party except as may otherwise be required by law, FERC, any Local Regulatory Authority or other provision of this ISO Tariff. Access by third parties other than authorized users to Meter Data held by the ISO shall be coordinated through the Scheduling Coordinator representing the relevant ISO Metered Entity that supplied the data and shall not be obtained directly from the ISO on any basis including, without limitation, by the polling of the ISO's revenue meter data acquisition and processing system via WEnet.

10.1.6 Data Retention by the ISO.

The ISO will maintain a record of all:

- (a) Meter Data provided to it;
- (b) Settlement Quality Meter Data provided to it; and
- (c) Settlement Quality Meter Data produced by it,

for a period of 18 months on site at the ISO's facilities and for a period of 10 years in the ISO's archive storage facilities. The ISO will, on reasonable notice, provide an Scheduling Coordinator with access to Meter Data or Settlement Quality Meter Data provided that the Scheduling Coordinator requesting access represented the entity that submitted that data at the time the data was submitted to the ISO.

10.2.1 Responsibilities of ISO Metered Entities.

10.2.1.1 Duty to Provide Meter Data.

ISO Metered Entities shall ensure that Meter Data from their meters directly connected to the ISO Controlled Grid or at interconnections thereto, including interconnections between utility Service Areas which have separate UFE calculations, is made available to the ISO revenue Meter Data acquisition and processing system in accordance with the requirements of these Sections 10.1 to 10.5 and Appendix O. Pursuant to this obligation, the ISO shall establish revenue metering protocols for such ISO Metered Entities.

10.2.1.2 Format for Data Submission.

10.2.1.2.1 Data Provided Directly From ISO Metered Entities.

ISO Metered Entities must ensure that the Meter Data obtained by MDAS directly from their revenue quality meters is raw, unedited and unaggregated Meter Data in kWh and kVarh values. The ISO will be responsible for the validation, editing and estimation of that Meter Data in order to produce Settlement Quality Meter Data.

10.2.1.2.2 Data Provided From Meter Data Servers.

ISO Metered Entities or Scheduling Coordinators representing ISO Metered Entities must ensure that the Meter Data provided to MDAS from a Compatible Meter Data Server identifies the relevant ISO Metered Entity and is raw, unedited and unaggregated Meter Data in kWh and kVarh values. The ISO will be responsible for the validation, editing and estimation of that Meter Data in order to produce Settlement Quality Meter Data.

10.2.1.3 Format for Data Requests.

Scheduling Coordinators may obtain Settlement Quality Meter Data relating to the ISO Metered Entities they represent by directly polling MDAS using the Meter Data Request Format. The ISO will use its best efforts to ensure that such data is made available to Scheduling Coordinators within 5 Business Days of the relevant Trading Day.

10.2.2 Duty to Install and Maintain Meters.

The ISO may require ISO Metered Entities to install, at their cost, additional meters and relevant metering system components, including real-time metering, at ISO specified Meter Points or other locations as deemed necessary by the ISO, in addition to those connected to or existing on the ISO Controlled Grid at the ISO Operations Date, including requiring the metering of transmission interfaces connecting Zones. In directing the addition of meters and metering system components that would impose increased costs on an ISO Metered Entity, the ISO shall give due consideration to whether the expected benefits of such equipment are sufficient to justify such increased costs. ISO Metered Entities, at their cost, shall install

and maintain, or cause to be installed and maintained, metering equipment and associated communication devices at ISO designated Meter Points to meet the requirements of this Section 10 and Appendix O. Nothing in this Section 10 shall preclude ISO Metered Entities from installing additional meters, instrument transformers and associated communications facilities at their own cost.

10.2.3 Metering Standards.

Each ISO Metered Entity shall ensure that each of its meters used to provide Meter Data to the ISO complies with the meter standards and accuracy requirements for meters set forth in Appendix J. In relation to revenue quality meters, the ISO will publish on the ISO Home Page, for information purposes and without liability on the part of the ISO, a list of the types and manufacturers of revenue quality meters that have been independently certified as meeting the standards for revenue quality meters referred to in the ISO Tariff.

10.2.4 Certification of Meters.

Each ISO Metered Entity that makes Meter Data available to the ISO shall ensure that metering facilities used to produce such Meter Data have been certified by the ISO as meeting the requirements of Sections 10.1 to 10.5 and Appendix O. Certification of the relevant metering facilities shall only be provided upon the production of such evidence as the ISO may reasonably require to demonstrate that the facilities in question have been documented, inspected and successfully tested by the ISO or an ISO Authorized Inspector for conformance to the standards and accuracy requirements referred to in Appendix J and Appendix O. Meters of End-Use ISO Metered Entities in place as of the ISO Operations Date are deemed to be certified as in compliance with Appendix J and such End-Users shall not be required to enter into meter service agreements with the ISO provided that their Scheduling Coordinators have entered into a meter service agreement with the ISO. ISO certification pursuant to this Section 10.2.4 shall not relieve the ISO Metered Entity from the obligation to ensure that its metering facilities continue to remain in compliance with the requirements of Sections 10.1 to 10.5 and Appendix O.

10.2.4.1 Requesting Certification.

An ISO Metered Entity seeking certification of its Metering Facilities shall independently engage an ISO Authorized Inspector to perform certification of its Metering Facilities. An ISO Metered Entity may request the ISO to perform the certification of its Metering Facilities if it would be impractical or impossible for that ISO Metered Entity to engage an ISO Authorized Inspector to perform the certification. The ISO may refuse any such request by an ISO Metered Entity if it is of the opinion that it is not impractical or impossible for that ISO Metered Entity to engage an ISO Authorized Inspector.

10.2.4.2 Certification by the ISO.

All requests made to the ISO to perform the certification of Metering Facilities must be made in accordance with the Technical Specifications and be accompanied by the documents referred to in the Technical Specifications. If the ISO agrees to perform the certification of Metering Facilities, the ISO and that ISO Metered Entity will agree the terms and conditions on which the ISO will undertake the certification including the assistance to be provided by the ISO Metered Entity, the responsibility for costs and the indemnities to be provided.

10.2.4.3 Criteria for Certification.

Subject to any exemption granted by the ISO under this ISO Tariff, the criteria for certifying the Metering Facilities of ISO Metered Entities pursuant to the ISO Tariff are the criteria set forth in the Technical Specifications.

10.2.4.4 Certificate of Compliance.

If the Metering Facilities satisfy the certification criteria (after taking into account any exemptions to the certification criteria granted by the ISO), the ISO will:

- (a) issue a Certificate of Compliance in respect of those Metering Facilities; and
- (b) provide the original Certificate of Compliance to the ISO Metered Entity that requested the certification of those Metering Facilities.

10.2.4.5 Obligation to Maintain Certification.

ISO Metered Entities must ensure that their Metering Facilities continue to comply with the certification criteria referred to in the ISO Tariff.

10.2.4.6 Revocation of Certification.

The ISO may revoke in full or in part any Certificate of Compliance if:

- (a) it has reasonable grounds to believe that all or some of the Metering Facilities covered by that Certificate of Compliance no longer meet the certification criteria for Metering Facilities contained in the ISO Tariff; and
- (b) it has given written notice to the relevant ISO Metered Entity stating that it does not believe that the identified Metering Facilities meet the certification criteria (including the reasons for that belief) and that ISO Metered Entity fails to satisfy the ISO, within the time period specified in the ISO's notice, that the Metering Facilities meet the certification criteria.

If the ISO revokes in full or part a Certificate of Compliance, the relevant ISO Metered Entity may seek recertification of the relevant Metering Facilities by requesting certification in accordance with Section 10.2.4.6. Such request must indicate that it relates to Metering Facilities in respect of which the ISO has previously revoked a Certificate of Compliance.

10.2.4.7 Changes to Certified Metering Facilities.

The ISO's approval must be obtained before any modifications or changes are made to any Metering Facilities of an ISO Metered Entity which have been certified pursuant to the ISO Tariff. The ISO may, at its discretion, require those Metering Facilities to be recertified.

10.2.5 ISO Authorized Inspectors.

10.2.5.1 Published List of Inspectors.

The ISO will publish on the ISO Home Page, for informational purposes only, a list of the ISO Authorized Inspectors and details of the procedure for applying to become an ISO Authorized Inspector. The ISO will, on request, provide a copy of that list to entities that do not have access to the ISO Home Page.

10.2.5.2 Current Certificates.

It is the responsibility of the relevant ISO Metered Entity to ensure that any inspector it engages to undertake the certification of its Metering Facilities holds a current certificate of approval issued by the ISO which authorizes that inspector to carry out the duties of an ISO Authorized Inspector.

10.2.6 Metering Communications.

The ISO's revenue meter data acquisition and processing system shall collect and process Meter Data made available by ISO Metered Entities pursuant to meter service agreements. Meter Data for ISO Metered Entities shall be made available to the ISO's revenue meter data acquisition and processing system either directly by the ISO Metered Entity or via a central data server which collects Meter Data for various ISO Metered Entities provided that the central data server does not aggregate or adjust that Meter Data. Meter Data on the ISO's revenue meter data acquisition and processing system may be accessed from the system's database by the ISO Settlement system, other ISO application programs, relevant Scheduling Coordinators and other authorized users as identified in the relevant meter service agreement ("other authorized users") subject to the ISO being satisfied that access by such authorized users will not adversely effect the security of data held by the ISO. ISO Metered Entities shall ensure that their metering facilities are compatible with the ISO revenue meter data acquisition and processing system for these purposes. The ISO may, at its discretion, exempt an ISO Metered Entity from the requirement to make Meter Data directly available to the ISO's revenue meter data acquisition and processing system, for example, where the installation of communication links is unnecessary, impracticable or uneconomic. The ISO shall maintain the revenue meter data acquisition and processing system and remedy any faults occurring in such system. Scheduling Coordinators and other authorized

users requiring Settlement Quality Meter Data for ISO Metered Entities they schedule or supply may obtain such data by polling the revenue meter data acquisition and processing system via WEnet in accordance with Appendix O. Scheduling Coordinators and other authorized users shall not poll the ISO revenue meter data acquisition and processing system for any other purpose, unless specifically authorized in their meter service agreement. During the period in which a Scheduling Coordinator is unable to poll directly the ISO revenue meter data acquisition and processing system, that Scheduling Coordinator will be responsible for providing the ISO with Settlement Quality Meter Data in accordance with Appendix O.

10.2.7 Meter Service Agreements for ISO Metered Entities.

10.2.7.1 Requirement for Meter Service Agreements.

The ISO shall establish meter service agreements with ISO Metered Entities for the collection of Meter Data. Such agreements shall specify that ISO Metered Entities shall make available to the ISO's revenue meter data acquisition and processing system, Meter Data meeting the requirements of these Sections 10.1 to 10.5 inclusive and Appendix O. The meter service agreement and the ISO Tariff Appendix O shall specify the format of Meter Data to be submitted, which shall be identified by TO, Distribution System, Zone, ISO Controlled Grid interface point and other information reasonably required by the ISO. Meter service agreements will identify other authorized users which are allowed to access the Settlement Quality Meter Data held by the ISO. The ISO will ensure that the relevant UDCs and TOs are included as other authorized users.

10.2.7.2 ISO Metered Entities.

ISO Metered Entities will either submit Meter Data directly to MDAS via Compatible Meter Data Servers or their revenue quality meters will be directly polled by MDAS.

10.2.7.3 Scheduling Coordinator Metered Entities.

Scheduling Coordinators must use Compatible Meter Data Servers to submit Settlement Quality Meter Data to the ISO for those Scheduling Coordinator Metered Entities that they represent. Scheduling Coordinators shall provide the ISO with the current password and any other information it needs to

access, at all times, the Compatible Meter Data Servers of those Scheduling Coordinators so as to ensure the security of those servers. Each Scheduling Coordinator must also provide the ISO with the WEnet protocol address of the Scheduling Coordinator's file server with which MDAS will interface to obtain or provide Settlement Quality Meter Data.

10.2.8 Security and Meter Data Validation Procedures.

The meter service agreement for each ISO Metered Entity and the ISO metering protocols shall set out, in such detail as the ISO may deem necessary, the Meter Data security and validation procedures that the ISO shall apply to the Meter Data made available by each ISO Metered Entity. The ISO may base the security and validation procedures on historical data or an appropriate alternative data source. The ISO shall correct or replace or cause to be corrected or replaced inaccurate or missing data. The procedure may include data correction and substitution algorithms which shall estimate, substitute and flag such inaccurate or missing data. Any necessary correction or replacement shall be approved by the ISO prior to the data being sent to the ISO Settlement system. Security and validation measures for existing Tie Point Meters shall be consistent with existing arrangements with the operators in adjacent Control Areas. Any additional measures or changes to the existing arrangements shall only be implemented upon mutual agreement of the ISO and the operator in the adjacent Control Area.

10.2.8.1 Meter Site Security.

Metering Facilities of ISO Metered Entities must meet the following requirements:

- (a) secondary devices that could have any impact on the performance of the Metering Facilities must be sealed; and
- (b) all Metering Facilities (including terminal servers and multiport devices) must be sealed.

10.2.8.2 Third Party Access to Meters.

(a) Local Access.

If an ISO Metered Entity desires to grant a third party local access to its revenue quality meters, those meters must be equipped with ISO certified RS-232 or optical ports and software. The ISO may set the password and any other security requirements for locally accessing the revenue quality meters of ISO Metered Entities so as to ensure the security of those meters and their Meter Data. The ISO may alter the password and other requirements for locally accessing those meters from time to time as it determines necessary. The ISO must provide ISO Metered Entities with the current password and other requirements for locally accessing their revenue quality meters. ISO Metered Entities must not give a third party local access to its revenue quality meters or disclose to that third party the password to its revenue quality meters without the ISO's prior approval which shall not unreasonably be withheld. ISO Metered Entities will be responsible for ensuring that a third party approved by the ISO to access its revenue quality meters only accesses the data it is approved to access and that the data are only accessed for the purposes for which the access was approved.

(b) Remote Access.

The ISO may set the password and any other security requirements for remotely accessing the revenue quality meters of ISO Metered Entities so as to ensure the security of those meters and their Meter Data. The ISO will alter the password and other requirements for remotely accessing those meters from time to time as it determines necessary. The ISO must provide ISO Metered Entities with the current password and other requirements for remotely accessing their revenue quality meters. ISO Metered Entities must not give a third party remote access to its revenue quality meters or disclose to that third party the password to its revenue quality meters without the ISO's prior approval which shall not unreasonably be withheld. ISO Metered Entities will be responsible for ensuring that a third party approved by the ISO to access its revenue quality meters only accesses the data it is approved to access and that the data are only accessed for the purposes for which the access was approved.

10.2.8.3 Third Party Access Withdrawn.

If, in the reasonable opinion of the ISO, access granted to a third party by an ISO Metered Entity in any way interferes or impedes with the ISO's ability to poll any revenue quality meter, the ISO may require that ISO Metered Entity to immediately withdraw any access granted to a third party.

10.2.8.4 MDAS Security.

The ISO will provide to entities that are permitted to access MDAS, the access password and any other requirements needed to access MDAS. The ISO must maintain the security and integrity of Meter Data and Settlement Quality Meter Data received by MDAS.

10.2.9 Validation, Editing and Estimating of Meter Data.

10.2.9.1 ISO Metered Entities.

Subject to any exemption granted by the ISO under Section 10.3.18, the raw Meter Data which ISO Metered Entities submit to the ISO will be processed by MDAS using the validation, editing and estimation procedures published on the ISO Home Page from time to time in order to produce Settlement Quality Meter Data.

10.2.9.2 Obligation to Assist.

At the request of the ISO, ISO Metered Entities shall assist the ISO in correcting or replacing defective data and in detecting and correcting underlying causes for such defects. Such assistance shall be rendered in a timely manner so that the Settlement process is not delayed.

10.2.9.3 Availability of Meter Data.

Subject to any exemption granted by the ISO under this ISO tariff, Meter Data must be recorded:

- (a) at 5-minute intervals by Loads and Generators providing Ancillary Services and/or Supplemental Energy; and
- (b) at 1-hour intervals by other ISO Metered Entities.

Meter Data will be collected regularly by MDAS in accordance with the frequency for collection determined by the ISO from time to time. The ISO may also collect Meter Data on demand. The ISO will issue such demands using voice communications. If the ISO issues a demand for Meter Data, the ISO Metered Entity from which the ISO demands that Meter Data must provide that Meter Data to the ISO within 10 minutes of receiving the demand from the ISO or, if that ISO Metered Entity has been granted an exemption from directly interfacing with MDAS pursuant to Section 10.3.18 within the time period specified in that exemption.

10.2.9.4 Failure to Achieve Required Standards.

Meter service agreements shall set out appropriate measures and rights the ISO may exercise upon any failure by the other party to meet the requirements for meter standards and accuracy set out in these Sections 10.1 to 10.5 inclusive.

10.2.9.5 ISO Imposed Penalties and Sanctions.

The ISO shall have the authority to impose penalties and sanctions, including but not limited to suspension of trading rights, if an ISO Metered Entity provides fraudulent metering data to the ISO. Such penalties shall be approved by FERC.

10.2.10.1 Requirement for ISO Approval.

After the ISO Operations Date, ISO Metered Entities may only install revenue quality meters on the low voltage side of step-up transformers if they have obtained the prior approval of the ISO in accordance with Section 10.2.10 of the ISO Tariff. ISO Metered Entities that have installed low voltage side metering, whether such installation was before or after the ISO Operations Date, shall apply the Transformer Loss Correction Factor in accordance with Section 10.2.10.4.

10.2.10.2 Request for Approval.

If an ISO Metered Entity wishes to install low voltage side metering, it shall submit a written request to the ISO. That ISO Metered Entity must:

- (a) request approval to apply the Transformer and/or Line Loss Correction Factor to its revenue quality meter or request approval to have MDAS apply the Transformer and/or Line Loss Correction Factor;
- (b) provide detailed reasons to support the request for low side metering;
- (c) provide all of the information in relation to the Transformer and/or Line Loss Correction Factor required by the Technical Specifications; and
- (d) any other information reasonably requested by the ISO.

10.2.10.3 ISO's Grounds for Approval.

The ISO shall approve a request made under Section 10.2.10.2 only if the ISO is satisfied that adequate accuracy and security of Meter Data obtained can be assured in accordance with Section 10.2.10 of the ISO Tariff. The ISO's rejection of such a request may be referred to the ISO ADR Procedures if, after using all reasonable good faith efforts, the ISO and an ISO Metered Entity are unable to reach agreement.

10.2.10.4 Application of Transformer and/or Line Loss Correction Factor.

ISO Metered Entities will apply the Transformer and/or Line Loss Correction Factor as set forth in the Technical Specifications. If the ISO has approved a request from an ISO Metered Entity for MDAS to apply the Transformer and/or Line Loss Correction Factor, MDAS will apply the Transformer and/or Line Loss Correction Factor set forth in the Technical Specifications. If MDAS is used to apply the Transformer and/or Line Loss Correction Factor, the ISO may require the ISO Metered Entity to pay the reasonable costs incurred by it in applying the Transformer and/or Line Loss Correction Factor

10.2.11 Audit, Testing Inspection and Certification Requirements.

ISO Metered Entities are subject to ISO audit, testing and certification requirements for their entire metering system(s), including all relevant communication facilities and instrument transformers. The ISO will have the right to either conduct any audit or test it considers necessary or to witness such audit or test carried out by the ISO Metered Entity or an ISO Authorized Inspector engaged by the ISO Metered Entity or the ISO to carry out those audits or tests.

10.2.12 Exemptions from ISO Metering Standards.

The ISO has the authority to grant exemptions from certain ISO metering standards for an ISO Metered Entity provided the ISO annually publishes details of the criteria the ISO will use when considering an application for an exemption and details of specific exemptions which are available. An ISO Metered Entity with an interim exemption shall provide site specific Settlement Quality Meter Data to the ISO in accordance with its meter service agreement and the Appendix O. A Generator connected directly to a UDC Distribution System and that sells its entire output to the UDC in which the Generator is located is not subject to the audit, testing or certification requirements of the ISO.

10.2.13 Maintenance of Metering Facilities.

10.2.13.1 Duty to Maintain Metering Facilities.

ISO Metered Entities must maintain their Metering Facilities so that those Metering Facilities continue to meet the standards prescribed by the ISO Tariff (including Appendix J).

If the Metering Facilities of an ISO Metered Entity require maintenance in order to ensure that they operate in accordance with the requirements of the ISO Tariff the ISO Metered Entity shall notify the ISO by telephone or other means specified by the ISO of the need for such maintenance. The ISO Metered Entity must also inform the ISO of the time period during which such maintenance is expected to occur. During that period, the ISO Metered Entity or its authorized representative shall be entitled to access those sealed Metering Facilities to which access is required in order to undertake the required maintenance.

During periods for which no Meter Data is available from a meter which has a current Certificate of Compliance, the ISO will substitute estimated meter data for that ISO Metered Entity using the estimation procedures referred to in Section 10.2.9. That estimated meter data will be used by the ISO in its Settlement and billing process.

10.2.13.2 Repairs.

If a revenue quality meter of an ISO Metered Entity requires repairs to ensure that it operates in accordance with the requirements of the ISO Tariff, the ISO Metered Entity must immediately notify the ISO of the need for repairing that meter and must ensure that those repairs are completed:

- (a) where there is no Check Meter installed, within 12 hours of the notification to the ISO; or
- (b) where there is a Check Meter installed, within 5 Business Days of the notification to the ISO.

During periods for which no Meter Data is available from a meter which has a current Certificate of Compliance, the ISO will substitute estimated meter data for that ISO Metered Entity using the estimation procedures referred to in Section 10.2.9. That estimated meter data will be used by the ISO in its Settlement and billing process.

In respect of Metering Facilities (other than a revenue quality meter) of an ISO Metered Entity that need repair, the ISO Metered Entity shall notify the ISO of that need and, after consultation with the ISO Metered Entity, the ISO will set the time period in which such repairs must be completed.

10.2.14 Installation of Additional Metering Facilities.

10.2.14.1 ISO Requirement to Install Additional Metering.

10.2.14.1.1 ISO Authority to Require Additional Metering Facilities.

The ISO has authority under Section 10.2.2 the ISO Tariff to require an ISO Metered Entity to install Metering Facilities in addition to those Metering Facilities on the ISO Controlled Grid at the ISO Operations Date. In directing the addition of meters and metering system components that would impose increased costs on an ISO Metered Entity, the ISO shall give due consideration to whether the expected benefits of such equipment are sufficient to justify such increased costs. An ISO Metered Entity may not commence installing those additional Metering Facilities until the ISO has approved its Proposal for Installation.

10.2.14.1.2 Requirement to Install.

If the ISO determines that there is a need to install additional Metering Facilities on the ISO Controlled Grid, it will notify the relevant ISO Metered Entity of that need. The ISO's notice to that ISO Metered Entity will include the following information:

- (a) the location of the Meter Point at which the additional Metering Facilities are required;
- (b) the date by which the ISO Metered Entity must install the relevant Metering Facilities;
- (c) the reason for the need to install the additional metering Facilities; and
- (d) any other information that the ISO considers relevant.

10.2.14.1.3 Obligations of ISO Metered Entity.

An ISO Metered Entity that is notified by the ISO that it is required to install additional Metering Facilities must:

- (a) give the ISO written confirmation of receipt of that notice within 3 Business Days of receiving that notice;
- (b) submit a Proposal for Installation to the ISO within 45 Business Days of receiving that notice. The Proposal for Installation must set out the following information:
 - i. a description of the proposed Metering Facilities to be installed (which shall include all relevant schematic drawings and one-line drawings);
 - ii. a proposed timetable for the installation; and
 - iii. any other information requested by the ISO in the notice referred to in Section 10.2.14.1.2.

10.2.14.1.4 Approval or Rejection of a Proposal for Installation.

The ISO may either:

- (a) unconditionally approve;
- (b) conditionally approve; or
- (c) reject, a Proposal for Installation.

10.2.14.1.5 Unconditional Approval.

If the ISO unconditionally approves a Proposal for Installation, it will promptly notify the ISO Metered Entity that the Proposal for Installation has been approved. The ISO Metered Entity shall then commence installation of the Metering Facilities in accordance with the Proposal for Installation.

10.2.14.1.6 Conditional Approval.

- (a) Notification of Conditional Approval.

If the ISO conditionally approves a Proposal for Installation, it will promptly notify the ISO Metered Entity that the Proposal for Installation has been conditionally approved and set out in that notice the conditions on which approval is granted and the time period in which each such condition must be satisfied by the ISO Metered Entity.

- (b) Ability to Satisfy Conditions.

If the ISO Metered Entity disputes any condition imposed by the ISO, the ISO Metered Entity must immediately notify the ISO of its concerns and provide the ISO with the reasons for its concerns. If the ISO Metered Entity gives the ISO such a notice, the ISO may amend or waive any of the conditions on which it granted its approval or it may require the ISO Metered Entity to satisfy other conditions. The ISO and the ISO Metered Entity will use all reasonable good faith efforts to reach agreement, and in the absence of agreement either entity may refer the dispute to the ISO ADR Procedures.

(c) Notification of Satisfaction of Conditions.

The ISO Metered Entity must promptly notify the ISO when each condition in the approval has been satisfied and provide to the ISO any information reasonably requested by the ISO as evidence that such condition has been satisfied.

(d) Confirmation of Satisfaction of Conditions.

If the ISO determines that a condition in the approval of the Proposal for Installation has been satisfied, it will give the ISO Metered Entity written confirmation that the condition has been satisfied.

(e) Unsatisfied Conditions.

If the ISO determines that a condition has not been satisfied after having received notice from an ISO Metered Entity, the ISO will notify the ISO Metered Entity that it does not consider the condition satisfied and shall set out in that notice the reason(s) that it does not consider the condition satisfied. If, after using all reasonable good faith efforts, the ISO and the ISO Metered Entity are unable to agree on whether that condition is satisfied, either entity may refer the dispute to the ISO ADR Procedures.

10.2.14.1.7 Rejection.

If the ISO rejects a Proposal for Installation, it will promptly notify the ISO Metered Entity that the Proposal for Installation has been rejected and set out in that notice the reason for its rejection. The ISO Metered Entity must submit to the ISO a revised Proposal for Installation within 14 Business Days of receiving such notice of rejection. If the ISO rejects for a second time a Proposal for Installation submitted by an ISO Metered Entity in respect of the same or similar notice issued by the ISO under Section 10.2.14.1.2, the ISO and the ISO Metered Entity will use all reasonable good faith efforts to reach agreement on the requirements and disputed items and in the absence of agreement either entity may refer the dispute to the ISO ADR Procedures.

10.2.14.1.8 ISO Metered Entities' Election to Install Additional Metering.

In accordance with Section 10.2.2 of the ISO Tariff, an ISO Metered Entity may choose to install additional metering, including Check Meters. If an ISO Metered Entity installs such additional metering, such metering must, unless the ISO agrees otherwise:

- (a) be installed and maintained at the ISO Metered Entity's cost;
- (b) be located on the ISO Metered Entity's side of any primary meter; and
- (c) not interfere with the accuracy of any primary meter and, if that primary meter is directly polled by the ISO, the ISO's ability to directly poll that meter.

Any Meter Data produced by any such additional metering may be used by the ISO for Settlement and billing purposes in the event of the failure, or during tests or repairs of, the primary meter provided that such additional metering has a current Certificate of Compliance, the ISO Metered Entity gives the ISO prior verbal notice that such meter will be used and the period for which it will be used and, if the primary meter is directly polled by the ISO, the additional metering must also be capable of being directly polled by the ISO.

10.3 Metering for Scheduling Coordinator Metered Entities.

10.3.1 Applicability.

The requirements set forth in this Section 10.3 shall apply only to Scheduling Coordinators representing Scheduling Coordinator Metered Entities. If a Scheduling Coordinator Metered Entity is also a Scheduling Coordinator, it shall be treated as a Scheduling Coordinator for the purposes of Section 10 of the ISO Tariff and any references to entities that such a Scheduling Coordinator represents shall be deemed to include that Scheduling Coordinator itself.

10.3.2 Responsibilities of Scheduling Coordinators and the ISO.

10.3.2.1 Duty to Provide Meter Data.

Scheduling Coordinators shall provide the ISO with Settlement Quality Meter Data for all of the Scheduling Coordinator Metered Entities served by the Scheduling Coordinator no later than the day specified in Section 10.3.6. Settlement Quality Meter Data for Scheduling Coordinator Metered Entities shall be either (1) an accurate measure of the actual consumption of Energy by each Scheduling Coordinator Metered Entity in each Settlement Period, or (2) for Scheduling Coordinator Metered Entities connected to a UDC Distribution System and meeting that Distribution System's requirement for load profiling eligibility, a profile of that consumption derived directly from an accurate cumulative measure of the actual consumption of Energy over a known period of time and an allocation of that consumption to Settlement Periods using the applicable Approved Load Profile.

10.3.2.2 Format for Data Submission.

Scheduling Coordinators shall submit Settlement Quality Meter Data to MDAS for the Scheduling Coordinator Metered Entities they represent using the Meter Data Exchange Format. Subject to any exemption granted by the ISO under Section 10.3.18, Scheduling Coordinators must ensure that Settlement Quality Meter Data submitted to the ISO is in intervals of:

- (a) 5 minutes for Loads and Generators providing Ancillary Services and/or Supplemental Energy; and
- (b) 1 hour for other Scheduling Coordinator Metered Entities.

Each Scheduling Coordinator shall submit Settlement Quality Meter Data for all of the Scheduling Coordinator Metered Entities that it schedules aggregated by:

- (a) Demand Zone, Load group or bus for Demand;
- (b) the relevant unit for Generation; or
- (c) the Scheduling Point for imports and exports.

The Settlement Quality Meter Data submitted by Scheduling Coordinators may be in either kWh or MWh values.

10.3.2.3 Format for Data Requests.

Scheduling Coordinators may obtain Settlement Quality Meter Data relating to the Scheduling Coordinator Metered Entities they represent by requesting extracts from MDAS using the Meter Data Request Format. The ISO will ensure that such data is made available in a timely manner.

10.3.3 Loss Factors.

Where a Scheduling Coordinator Metered Entity is connected to a UDC's Distribution System, the responsible Scheduling Coordinator shall adjust the Meter Data by an estimated Distribution System loss factor to derive an equivalent ISO Controlled Grid level measure. Such estimated Distribution System loss factors shall be approved by the relevant Local Regulatory Authority prior to their use. The Scheduling Coordinator shall aggregate its equivalent ISO Controlled Grid-level Meter Data for Scheduling Coordinator Metered Entities

10.3.4 Load Profile Authorization.

Scheduling Coordinators shall be responsible for obtaining all necessary authorizations from Local Regulatory Authorities having jurisdiction over the use of profiled Meter Data in any Settlement process in which load profiles are used to allocate consumption to Settlement Periods.

10.3.5 Communication of Meter Data.

Each Scheduling Coordinator shall submit Settlement Quality Meter Data for Scheduling Coordinator Metered Entities to the ISO.

10.3.6 Timing of Meter Data Submission.

Scheduling Coordinators shall submit either hourly time-stamped Settlement Quality Meter Data for Scheduling Coordinator Metered Entities or profiled cumulative Settlement Quality Meter Data to the ISO for each Settlement Period in a Trading Day within forty-five (45) calendar days of that Trading Day.

Scheduling Coordinators shall submit Settlement Quality Meter Data to the ISO when required to do so by this ISO Tariff and the ISO Payments Calendar. Scheduling Coordinators must also submit Settlement Quality Meter Data on demand. The ISO will issue such demands using voice communications. If the ISO issues a demand for Settlement Quality Meter Data, the Scheduling Coordinator from which the ISO demands that data must submit it to the ISO within 4 hours of receiving the demand from the ISO.

10.3.7 Meter Standards.

Each Scheduling Coordinator, in conjunction with the relevant Local Regulatory Authority, shall ensure that each of its Scheduling Coordinator Metered Entities connected to and served from the Distribution System of a UDC shall be metered by a revenue meter complying with any standards of the relevant Local Regulatory Authority or, if no such standards have been set by that Local Regulatory Authority, the metering standards set forth in Appendix J.

10.3.8 Access to Meter Data.

The ISO has complete authority over rights of access to (and has authority to deny access to) its revenue meter data acquisition and processing system including servers (where used), interface equipment, and software needed to accept Settlement Quality Meter Data from Scheduling Coordinator Metered Entities for Settlement, billing and related purposes. Each Scheduling Coordinator, on behalf of itself and Market Participants that it serves or represents, acknowledges this ISO authority as a condition of access to the ISO Controlled Grid.

10.3.8A Collection of Meter Data.

10.3.8A.1 Responsibility of Scheduling Coordinators.

Each Scheduling Coordinator shall be responsible for the collection of Meter Data from the Scheduling Coordinator Metered Entities it represents and for ensuring that the Settlement Quality Meter Data supplied to the ISO meets the requirements of this Section 10.3

10.3.9 Certification of Meters.

Scheduling Coordinators shall ensure that revenue meters and related metering facilities of those Scheduling Coordinator Metered Entities whom they represent are certified in accordance with any certification criteria prescribed by the relevant Local Regulatory Authority or, if no such criteria have been prescribed by that Local Regulatory Authority. Scheduling Coordinators shall upon request of the ISO supply promptly copies of all certificates issued by the relevant Regulatory Authority. The End Use Meter of an ISO Metered Entity or a Scheduling Coordinator Metered Entity in place as of the ISO Operations Date is deemed to be certified as in compliance with Appendix J. Once certified, meters for Scheduling Coordinator Metered Entities need not be recertified provided such meters are maintained so as to meet the standards and accuracy requirements prescribed by any relevant Local Regulatory Authority or, if no such standards have been prescribed by that Local Regulatory Authority, such requirements as referred to in Appendix J. Recertification is not required by the ISO upon an election by a Scheduling Coordinator Metered Entity to change its Scheduling Coordinator from which it takes service.

10.3.10 Requirement for Audit and Testing.

(a) Audit and Testing by Scheduling Coordinator

Each Scheduling Coordinator shall at least annually conduct (or engage an independent, qualified entity to conduct) audits and tests of the Metering Facilities of the Scheduling Coordinator Metered Entities that it represents and the Meter Data provided to the Scheduling Coordinator in order to ensure compliance with all applicable requirements of any relevant Local Regulatory Authority. Scheduling Coordinators shall undertake any other actions that are reasonable necessary to ensure the accuracy and integrity of the Settlement Quality Meter Data provided by them to the ISO.

(b) Audit and Testing by ISO

Subject to any applicable Local Regulatory Authority requirements, the Metering Facilities and data handling and processing procedures of Scheduling Coordinators and Scheduling Coordinator Metered Entities are subject to audit and testing by the ISO or an ISO Authorized Inspector in accordance with Section 10.3.14.2 of the ISO Tariff. Subject to any applicable Local Regulatory Authority requirements,

the ISO will have the right to either conduct any audit or test it considers necessary or to witness such audit or test carried out by the Scheduling Coordinator, Scheduling Coordinator Metered Entity or an ISO Authorized Inspector engaged by the Scheduling Coordinator, Scheduling Coordinator Metered Entity or the ISO to carry out those audits or tests.

10.3.11 Scheduling Coordinator to Ensure Certification.

If the relevant Local Regulatory Authority has not prescribed any certification criteria for the Metering Facilities of a Scheduling Coordinator Metered Entity, the Scheduling Coordinator representing that Scheduling Coordinator Metered Entity must promptly notify the ISO in writing that no such criteria have been prescribed. That Scheduling Coordinator will then be responsible for ensuring that the Scheduling Coordinator Metered Entities it represents obtain and maintain Certificates of Compliance in respect of all of the Metering Facilities of those Scheduling Coordinator Metered Entities in accordance with Section 10.2.4. Scheduling Coordinators must engage an ISO Authorized Inspector to perform the certification of any Metering Facilities that are to be certified under the ISO Tariff.

10.3.12 Certification of Meter Data Servers.

Subject to any exemption granted by the ISO under 10.3.18 the ISO will not accept Settlement Quality Meter Data relating to a Scheduling Coordinator Metered Entity from a meter data server unless that meter data server is a Compatible Meter Data Server.

10.3.12.1 Confirmation of Certification.

On the written request of the ISO, each Scheduling Coordinator must give the ISO written confirmation that the Metering Facilities of each Scheduling Coordinator Metered Entity that it represents are certified in accordance with either the criteria of the relevant Local Regulatory Authority or the criteria prescribed by this Section within 5 Business Days of receiving a request from the ISO.

10.3.12.2 Deemed Certification.

In accordance with Section 10.3.9 of the ISO Tariff, those revenue quality meters of Scheduling Coordinator Metered Entities that are subject to certification pursuant to the ISO Tariff and which were

installed and operational as of the ISO Operations Date will be deemed to be certified for the purposes of the ISO Tariff. Revenue quality meters that have been fully installed as of the ISO Operations Date but which are not operational as of that date because they were undergoing maintenance or repairs will also be deemed to be certified in accordance with the ISO Tariff.

10.3.13 Meter Service Agreements for Scheduling Coordinator Metered Entities.

The ISO shall enter into meter service agreements with Scheduling Coordinators responsible for providing Settlement Quality Meter Data for Scheduling Coordinator Metered Entities to the ISO. Such agreements shall specify that Scheduling Coordinators require their Scheduling Coordinator Metered Entities to adhere to the meter requirements set forth in this Section 10.3.

10.3.14 Approval by Local Regulatory Authority of Security and Validation Procedures.

Scheduling Coordinators shall be responsible for obtaining any necessary approval of the relevant Local Regulatory Authority to its proposed security, validation, editing and estimation procedures. The ISO will not perform any validation, editing or estimating on the Settlement Quality Meter Data it receives from Scheduling Coordinators.

10.3.14.1 UDC and TO Agreements.

Each Scheduling Coordinator shall be responsible for obtaining any necessary consent from the UDCs on whose Distribution Systems or the Participating TOs on whose transmission facilities the Scheduling Coordinator has Scheduling Coordinator Metered Entities as is necessary to give effect to the procedures governing Meter Data validation and security and inspection and testing of metering facilities. Scheduling Coordinators must verify with the relevant UDC the identity of each Scheduling Coordinator Metered Entity they represent and must notify the UDC of any discrepancies of which they become aware.

10.3.14.2 Scheduling Coordinator Metered Entity Certification, Testing and Audit.

Subject to any Local Regulatory Authority requirements, the ISO reserves the right to inspect, test and otherwise audit the entire metering systems of the Scheduling Coordinator Metered Entity connected to the ISO Controlled Grid, from the Meter Data server to the metering system(s), and such systems shall

be subject to ISO audits and tests. However, only the Meter Data server supplying the ISO is subject to ISO certification requirements.

The Scheduling Coordinator or its designated representative shall provide the ISO with all such information, assistance and cooperation the ISO reasonably requires in order to conduct such inspections, tests and audits.

10.3.14.3 Failure to Achieve Required Standards.

Subject to any Local Regulatory Authority requirements, meter service agreements shall set out appropriate measures and rights the ISO may exercise upon any failure by the other party to meet the requirements for meter standards and accuracy set out in this Section 10.3.

10.3.14.4 Data Access.

Meter Data of a Scheduling Coordinator Metered Entity remains the property of that Scheduling Coordinator Metered Entity and shall be made available to third parties only with its express permission or as otherwise required by law or provided for in this ISO Tariff. The ISO shall be granted access to Meter Data of Scheduling Coordinator Metered Entities obtained by Scheduling Coordinators.

10.3.15 Exemptions from ISO Metering Standards.

The ISO has the authority to grant exemptions from certain ISO metering standards for Scheduling Coordinator Metered Entities that are subject to ISO metering standards provided the ISO annually publishes details of the criteria the ISO will use when considering an application for an exemption and details of specific exemptions which are available.

10.3.16 COMMUNICATIONS

10.3.16.1 Facilities Provided by the ISO.

The ISO will provide the facilities referred to in this 10.3.16.1 to acquire Meter Data from ISO Metered Entities and receive Settlement Quality Meter Data from Scheduling Coordinators.

10.3.16.1.1 MDAS Master Station.

The MDAS master station will have a redundant configuration. The primary master station is located in Folsom, the redundant master station is located in Alhambra.

10.3.16.1.2 WEnet.

MDAS will use WEnet to acquire Meter Data from ISO Metered Entities and receive Settlement Quality Metered Data from Scheduling Coordinators. WEnet is an ISO-provided Wide Area Network (WAN). WEnet will use the TCP/IP networking protocol.

10.3.16.1.3 Points of Presence.

WEnet will have a Point of Presence (POP) in the general vicinity of most ISO Metered Entities and Scheduling Coordinators. The POP is the interface point between WEnet and the facilities provided by ISO Metered Entities and Scheduling Coordinators pursuant to 10.3.16.2 and 10.3.16.3.

10.3.16.1.4 Facilities Failure.

In the event that the primary or redundant MDAS master station or WEnet fails, the procedures referred to in Appendix A will be followed by the ISO, ISO Metered Entities and Scheduling Coordinators.

10.3.16.2 Facilities Provided by ISO Metered Entities.

ISO Metered Entities must provide the telecommunication facilities referred to in 10.3.16.2.1 to 10.3.16.2.3 inclusive to connect their Compatible Meter Data Servers to the WEnet POP.

10.3.16.2.1 Telecommunications Channels.

The ISO Metered Entity must provide one of the following types of telecommunication channels from the WEnet POP to its Compatible Meter Data Servers:

- (a) Digital leased line;
- (b) ISDN channel; or
- (c) frame relay channel.

With the ISO's approval, the revenue quality meters of two or more ISO Metered Entities may be served by one telecommunications channel.

10.3.16.2.2 Router/Terminal Server.

ISO Metered Entities must provide router/terminal servers to interface the telecommunication channels to revenue quality meters. Each revenue quality meter will use an RS-232 interface nominally operating at 9600 bits/second.

10.3.16.2.3 Meter Data Server.

ISO Metered Entities must use a Compatible Meter Data Server to interface with MDAS.

10.3.16.3 Facilities provided by Scheduling Coordinators.

Scheduling Coordinators must use a Compatible Meter Data Server to interface with MDAS.

10.3.17 METER IDENTIFICATION.

10.3.17.1 Scheduling Coordinator Metered Entities.

If a Scheduling Coordinator Metered Entity is required to identify its revenue quality meters by the relevant:

- (a) Local Regulatory Authority; or
- (b) UDC,

then the Scheduling Coordinator representing that Scheduling Coordinator Metered Entity must, at the ISO's request, provide the ISO with a copy of that information within 5 Business Days of a request by the ISO in a format to be prescribed by the ISO.

If a Scheduling Coordinator Metered Entity is not required by either the relevant Local Regulatory Authority or UDC to identify its revenue quality meters, the Scheduling Coordinator representing that Scheduling Coordinator Metered Entity shall maintain an accurate record of the revenue quality meter of each of the Scheduling Coordinator Metered Entities that it represents from time to time. The record maintained by Scheduling Coordinators must include the information set out in the Technical

Specifications. The Scheduling Coordinator must, at the ISO's request, provide the ISO with a copy of any information contained in that record within 5 Business Days of a request by the ISO in a format to be prescribed by the ISO.

10.3.18 EXEMPTIONS FROM COMPLIANCE.

10.3.18.1 Authority to Grant Exemptions.

In addition to the specific exemptions granted under the ISO Tariff, the ISO has the authority under the ISO Tariff to grant exemptions from compliance with certain requirements imposed by the ISO Tariff.

10.3.18.2 Guidelines for Granting Exemptions.

The ISO will use the following guidelines when considering applications for exemptions from compliance with the ISO Tariff.

(a) Publication of Guidelines

The ISO will from time to time publish the general guidelines that it may use when considering applications for exemptions so as to achieve consistency in its reasoning and decision making and to give prospective applicants an indication of whether an application will be considered favorably.

(b) Publication of Exemption Applications

The ISO will promptly publish on the ISO Home Page a description of each application it receives for an exemption.

(c) Publication of Decision

The ISO will publish on the ISO Home Page details of whether the application was approved or rejected by it and, if the ISO considers it appropriate, the reasons for rejecting the application.

(d) Class Exemptions

In addition to exemptions granted to individual entities, the ISO may grant exemptions that will apply to a class of entities. The ISO may grant class exemptions whether or not it has received any application for an exemption. The ISO will publish details of the class exemptions it has granted on the ISO Home Page.

10.3.18.3 Procedure for Applying for Exemptions.

All applications to the ISO for exemptions from compliance with the requirements of the ISO Tariff must be made in writing addressed to the Meter and Data Acquisition Manager, Client Service Department. The ISO will confirm receipt of each application it receives within 3 Business Days of receiving the application. The ISO will decide whether to grant the exemption within 45 Business Days of receiving the application. At any time during that period, the ISO may require the applicant to provide additional information in support of its application. The applicant must provide such additional information to the ISO within 5 Business Days of receiving the request for additional information or within such other period as the ISO may notify to the applicant. If the ISO makes a request for additional information more than 40 Business Days after the date on which it received the application, the ISO will have an additional 7 Business Days after receiving that additional information in which to consider the application. If the applicant does not provide the additional information requested, the ISO may refuse the application in which case it will notify the applicant that its application has been rejected for failure to provide the additional information.

10.3.18.4 Information to be Included in the Application.

The application submitted to the ISO must provide:

- (a) a detailed description of the exemption sought (including specific reference to the relevant section(s) of the ISO Tariff giving the ISO authority to grant the exemption) and the facilities to which the exemption will apply;
- (b) a detailed statement of the reason for seeking the exemption (including any supporting documentation);
- (c) details of the entity(s) (if any) to which the exemption will apply;
- (d) details of the location (if any) to which the exemption will apply;
- (e) details of the period of time for which the exemption will apply (including the proposed start and finish dates of that period); and

(f) any other information requested by the ISO.

10.3.18.5 Permitted Exemptions.

10.3.18.5.1 Exemptions from Providing Meter Data Directly to MDAS.

(a) General

The ISO has the authority under 10.2.6 of the ISO Tariff to exempt ISO Metered Entities from the requirement to make Meter Data directly available to the ISO via MDAS. In addition to the specific exemptions provided under 10.3.18.5.1, the ISO may, at its discretion, grant such an exemption where it considers the requirement to install communication links (or related facilities) between the ISO Metered Entity and WEnet to allow the ISO to directly poll that ISO Metered Entity would be unnecessary, impractical or uneconomic.

(b) Specific Exemptions Available

i. Tie Points

Meters located at tie points are exempted from the requirement that they be directly polled by the ISO provided that the meters at those tie points are revenue quality and they provide hourly, raw Meter Data to the ISO's Power Management System.

The entities responsible for Tie Point Meters must designate a primary meter and the entity responsible for providing the relevant Meter Data to the ISO. Meter Data from any other meter located at that tie point may be provided to the ISO in the event that the primary meter is unable to provide Meter Data to the ISO.

Existing Tie Point Meters will be exempt from the metering standards referred to in the ISO Tariff, if such meters are only used to measure bi-directional Energy.

ii. Generation not Providing Regulation

ISO Metered Entities that are Generators or Participating Generators that are not directly connected to the ISO Controlled Grid and which do not provide Regulation may request the ISO for an exemption from

the requirement that they be directly polled by the ISO in which case they will be treated as Scheduling Coordinator Metered Entities for the purposes of the ISO Tariff.

iii. Scheduling Coordinators inability to directly poll MDAS

If a Scheduling Coordinator does not have the ability as at the ISO Operations Date to directly poll MDAS for the Settlement Quality Meter Data of the ISO Metered Entities that it represents, that Scheduling Coordinator shall have a period of 12 months from the ISO Operations Date in which to install the necessary equipment to enable it to directly poll MDAS. During the period in which a Scheduling Coordinator is unable to directly poll MDAS, that Scheduling Coordinator will be responsible for providing the ISO with Settlement Quality Meter Data for its ISO Metered Entities in accordance with the ISO Tariff.

iv. Generator Profiling

The ISO may permit Generators and Participating Generators with Generating Units of less than 1 MW to use generator profiles, provided that such profiles are reconciled against revenue quality cumulative meters and the ISO has given prior approval to the use of the proposed generator profile. The revenue quality meters used by such Generators and Participating Generators will not be required to have a current Certificate of Compliance at the ISO Operations Date. However, such meters maybe required to have a Certificate of Compliance within a time period prescribed by the ISO after consultation with the relevant Generator or Participating Generator.

v. Small Remote Generators

Remote Generators of less than 10 MW and capacity factors of less than 20% over the past three years, may be granted an exemption from the requirement to be directly polled by the ISO provided that the ISO is able to receive Meter Data for that Generator from a Compatible Meter Data Serve.

10.3.18.5.2 Exemptions from Meter Standards.

(a) General

The ISO has the authority under 10.2.12 of the ISO Tariff to exempt ISO Metered Entities from the requirement to comply with the meter standards referred to in the ISO Tariff.

(b) Specific Exemptions Available

i. Data Storage for Existing Meters

Revenue quality meters installed as at the ISO Operations Date are required to have 30 days data storage capacity (new revenue quality meters are required to have 60 days data storage capacity). Existing revenue quality meters that otherwise comply with the meter standards referred to in the ISO Tariff but which do not have 30 days data storage will be exempted from that requirement if there is alternative time stamped meter data storage of 30 days or more.

ii. Voltage Transformers

ISO Metered Entities will be exempt from the requirement to install Voltage Transformers (VT) at 500 kV and higher voltage levels provided that those ISO Metered Entities install Capacity Coupled Voltage Transformers (CCVT) that meet the metering standards referred to in the ISO Tariff. The ISO Metered Entity must establish a testing program to ensure that the CCVT remains within the ISO's accuracy requirements. A copy of such test program must be supplied to the ISO and the ISO may require amendments and/or additions to that program that it reasonably believes are necessary to ensure the accuracy of the CCVT.

iii. Loss Correction Factors

The ISO may grant an ISO Metered Entity an exemption from compliance with the metering standards referred to and the ISO Tariff if, in the ISO's sole discretion, applicable loss correction factors can be applied to existing meters without any materially adverse effect on the accuracy or security of the Meter Data obtained from such meters.

iv. 5 Minute Interval Data

Generators that are ISO Metered Entities and that provide Ancillary Services to the ISO will not be required to provide the ISO with 5 minute interval data until such time as specified by the ISO. Until such time as the ISO requires 5 minute interval data, these entities will be required to provide the ISO with hourly interval data.

v. Request for Direct Polling

Scheduling Coordinators may request the ISO to grant an exemption from the requirement to provide Settlement Quality Meter Data to the ISO for Scheduling Coordinator Metered Entities they represent if those entities are Generators which have requested the ISO, and the ISO has agreed, to directly poll them for Meter Data. Such Generators will be treated as ISO Metered Entities and must comply with all of the requirements relating to ISO Metered Entities in accordance with the ISO Tariff. The Scheduling Coordinator representing such Generators will be required to apply the relevant distribution loss factors to that Generator's Meter Data (the Scheduling Coordinator may obtain that Meter Data from the ISO).

vi. QF Exemptions

If a QF sells all of its Energy (excluding any Energy consumed by auxiliary load equipment electrically connected to that QF at the same point or any Energy sold through "over the fence" arrangements as authorized by Section 218(b) of the California Public Utilities Code) and Ancillary Services to the UDC in whose Service Area it is located pursuant to an existing power purchase agreement (which is authorized under Section 218(b) of the California Public Utilities Code) and there is any inconsistency between that existing power purchase agreement, Section 10 of the ISO Tariff or Appendix J to the ISO Tariff, the existing power purchase agreement shall prevail to the extent of that inconsistency for the term of the agreement. In this context, an existing power purchase agreement shall mean an agreement which has been entered into and is effective as of December 20, 1995.

vii. Combining Generation

A metered entity may elect to meter a group of Generating Units which are electrically connected to the same point by combined total generation output or by individual Generating Unit provided that those Generating Units are Scheduled in the same fashion as they are metered and the Generating Units are not individually providing Ancillary Services.

10.3.18.5.3 Exemptions from Audit, Testing or Certification.

The ISO has the authority under 10.2.12 of the ISO Tariff to exempt ISO Metered Entities from the metering standards referred to in the ISO Tariff.

11 ISO SETTLEMENTS AND BILLING.

11.1.1 The ISO shall calculate, account for and settle transactions in accordance with the following principles:

11.1.2 The ISO shall be responsible for calculating Settlement balances for all transactions carried out by Scheduling Coordinators on the ISO Controlled Grid in each Settlement Period

11.1.3 The ISO shall carry out all Settlements in accordance with Meter Data provided pursuant to the requirements of Section 10 of this ISO Tariff;

11.1.4 The ISO shall create and maintain computer back-up systems, including off-site storage of all necessary computer hardware, software, records and data at an alternative location that, in the event of a Settlement system breakdown at the primary location of the day-to-day operations of the ISO, could serve as an alternative location for day-to-day Settlement operations within a reasonable period of time; and

11.1.5 The ISO shall retain all Settlement data records for a period which, at least, allows for the re-run of data as required by this ISO Tariff and any adjustment rules of the Local Regulatory Authority governing the Scheduling Coordinators and their End-Use Customers;

11.1.6 The ISO shall settle the following charges in accordance with Section 11.2 of this ISO Tariff: (1) Grid Management Charge; (2) Grid Operations Charge; (3) Ancillary Services charges; (4) Imbalance Energy charges; (5) Usage Charges; (6) High Voltage Access Charges and Transition Charges; (7) Wheeling Access Charges; (8) Voltage Support and Black Start charges; and Reliability Must-Run Charges; (9) Default Interest Charges; and Participating Intermittent Resource Fees.

11.1.7 Financial Transaction Conventions and Currency.

The following conventions have been adopted in defining sums of money to be remitted to or received by the ISO:

- (a) where the ISO is to receive a sum of money under this Section, this is defined as a "Charge";

- (b) where the ISO is to required to pay a sum of money under this Section, this is defined as a "Payment".
- (c) All financial transactions are denominated in US dollars and cents.
- (d) All payments by the ISO to Scheduling Coordinators, Black Start Generators and Participating TOs shall be made by Fed-Wire. All payments to the ISO by Scheduling Coordinators, Black Start Generators and Participating TOs shall be made by Fed-Wire.

11.2 Calculations of Settlements.

The ISO shall calculate, account for and settle, based on the Settlement Quality Meter Data it has received, or, if Settlement Quality Meter Data is not available, based on the best available information or estimate it has received, the following charges in accordance with this ISO Tariff.

11.2.1 Grid Management Charge.

The Grid Management Charge will be levied in accordance with this Section and Appendix F, Schedule 1 of this ISO Tariff. The Charges shall accrue on a monthly basis.

11.2.2 Grid Operations Charge.

The Grid Operations Charge will be levied in accordance with Section 27.1.3 and Appendix F, Schedule 2 of this ISO Tariff. These charges shall accrue on a monthly basis.

11.2.2.1 ISO's Obligations.

11.2.2.1.1 FERC's Uniform System of Accounts.

The ISO shall maintain a set of financial statements and records in accordance with the FERC's Uniform System of Accounts.

11.2.2.1.2 [Not Used]

11.2.2.2 Costs Included in the Grid Management Charge.

11.2.2.2.1 [Not Used]

11.2.2.2.2 Operating Costs.

Budgeted annual operating costs, which shall include all staffing costs including remuneration of contractors and consultants, salaries, benefits and any incentive programs for employees, costs of operating, replacing and maintaining ISO systems, lease payments on facilities and equipment necessary for the ISO to carry out its business, and annual costs of financing the ISO's working capital and other operating costs ("Operating Costs").

11.2.2.2.3 Financing Costs.

The financing costs that are approved by the ISO Governing Board, including capital expenditures that may be financed over such period as the ISO Governing Board shall decide. Financing Costs shall also include the ISO start up and development costs standing to the credit of the ISO Memorandum Account plus any additional start up or development costs incurred after the date of Resolution E-3459 (July 17, 1996), plus any additional capital expenditure incurred by the ISO in 1998 ("Start Up and Development Costs"). The amortized amount to be included in the Grid Management Charge shall be equal to the amount necessary to amortize fully all Start Up and Development Costs over a period of five (5) years, or such longer period as the ISO Governing Board shall decide ("Financing Costs").

11.2.2.2.4 Operating and Capital Reserves Cost.

The budgeted annual cost of pay-as-you-go capital expenditures and reasonable coverage of debt service obligations. Such reserves shall be utilized to minimize the impact of any variance between forecast and actual costs throughout the year ("Operating and Capital Reserves Costs").

11.2.2.3 Allocation of the Grid Management Charge Among Scheduling Coordinators.

The costs recovered through the Grid Management Charge shall be allocated to the eight service charges that comprise the Grid Management Charge. If the ISO's revenue requirement for any service charge

changes from the most recent FERC-approved revenue requirement for that service charge, the costs recovered through that service charge shall be delineated in a filing to be made at FERC as set forth in Section 11.2.2.4. The eight service charges are as follows:

- (1) Core Reliability Services - Demand Charge,
- (2) Core Reliability Services – Energy Exports Charge
- (3) Energy Transmission Services Net Energy Charge,
- (4) Energy Transmission Services Uninstructed Deviations Charge,
- (5) Forward Scheduling Charge,
- (6) Congestion Management Charge,
- (7) Market Usage Charge, and
- (8) Settlements, Metering, and Client Relations Charge.

The eight charges shall be levied separately monthly in arrears on all Scheduling Coordinators based on the billing determinants specified below for each charge in accordance with formulae set out in Appendix F, Schedule 1, Part A of this Tariff, subject to the requirements set out in Appendix F, Schedule 1, Part F of this Tariff.

11.2.2.3.1 Core Reliability Services – Demand Charge.

The Core Reliability Services - Demand Charge for a Scheduling Coordinator's Load that is not associated with Energy Exports is calculated using the Scheduling Coordinator's metered non-coincident peak hourly Demand during the month (in megawatts) less the volume of Energy Exports included in the Scheduling Coordinator's non-coincident peak hourly Demand for the month, if any; provided that if the Scheduling Coordinator's metered non-coincident peak hour during the month occurs during the hours ending 0100 through 0600, or during the hours ending 2300 through 2400 the rate shall be sixty-six (66) percent of the standard CRS rate. The standard rate for the Core Reliability Services – Demand Charge is determined by dividing the GMC costs allocated to this service category, including a specified

percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total of the forecasted metered non-coincident peak hourly Demand for all months during the year (excluding the portion of such Demand associated with Energy Exports, if any), reduced by thirty-four (34) percent of the sum of all Scheduling Coordinators' metered non-coincident peak hour during the month occurs between the hour ending 2300 and the hour ending 0600, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

11.2.2.3.2 Core Reliability Services – Energy Exports Charge.

The Core Reliability Services – Energy Exports Charge for the load associated with a Scheduling Coordinator's Energy Exports is calculated using the Scheduling Coordinator's metered volume of Energy Exports (in megawatt-hours); The rate for the Core Reliability Services – Energy Exports Charge is determined by dividing the GMC costs allocated to the Core Reliability Services service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

11.2.2.3.3 Energy Transmission Services Net Energy Charge.

The Energy Transmission Services Net Energy Charge for each Scheduling Coordinator is calculated using that Scheduling Coordinator's Metered Control Area Load (in megawatt-hours). The rate for the Energy Transmission Services Net Energy Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted Metered Control Area Load, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

11.2.2.3.4 Energy Transmission Services Uninstructed Deviations Charge.

The Energy Transmission Services Uninstructed Deviations Charge for each Scheduling Coordinator is calculated using that Scheduling Coordinator's net uninstructed deviations by Settlement Interval. The rate for the Energy Transmission Services Uninstructed Deviations Charge is determined by dividing the

GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted net uninstructed deviations by Settlement Interval according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

11.2.2.3.5 Forward Scheduling Charge.

The Forward Scheduling Charge for each Scheduling Coordinator is calculated using the sum of that Scheduling Coordinator's Final Hour-Ahead Schedules, including all awarded Ancillary Services bids, with a value other than 0.03 MW. The Forward Scheduling Charge attributable to Final Hour-Ahead Schedules for Inter-Scheduling Coordinating Energy and Ancillary Service Trades for each Scheduling Coordinator is fifty (50) percent of the standard Forward Scheduling Charge. The rate for the Forward Scheduling Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted Final Hour-Ahead Schedules and awarded Ancillary Service bids submitted to the ISO, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

11.2.2.3.6 Congestion Management Charge.

The Congestion Management Charge for each Scheduling Coordinator is calculated as the product of the rate for the Congestion Management Charge and the absolute value of the net scheduled inter-zonal flow (excluding flows pursuant to Existing Contracts) per path for that Scheduling Coordinator. The rate for the Congestion Management Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted inter-zonal scheduled flow (excluding flows pursuant to Existing Contracts) per path in MWh, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

11.2.2.3.7 Market Usage Charge.

The Market Usage Charge for each Scheduling Coordinator is calculated using the absolute value of the Scheduling Coordinator's market purchases and sales of Ancillary Services, Supplemental Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with uninstructed deviations being netted by Settlement Interval). The rate for the Market Usage Charge is determined by dividing the GMC costs allocated to this service category, including a specified percentage of the costs for the Settlements, Metering, and Client Relations Charge determined to be in excess of what is recovered by that charge, by the total forecasted number of market purchases and sales, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

11.2.2.3.8 Settlements, Metering, and Client Relations Charge.

The Settlements, Metering, and Client Relations Charge for each Scheduling Coordinator is fixed at \$500.00 per month, per Scheduling Coordinator ID with an invoice value other than \$0.00 in the current trade month, as indicated in Appendix F, Schedule 1, Part A of this Tariff. Excess GMC costs related to the provision of these services that are not recovered through this charge are allocated to the other GMC service categories as specified above and in Appendix F, Schedule 1, Part E of this Tariff.

11.2.2.4 Calculation and Adjustment of the Grid Management Charge.

The eight charges set forth in Section 11.2.2.3 that comprise the Grid Management Charge shall be calculated through the formula set forth in Appendix F, Schedule 1, Part A of this Tariff. The formula set forth in Appendix F, Schedule 1, Part C of this Tariff sums the Operating Costs (less any available expense recoveries), Financing Costs, and Operating and Capital Reserves Costs associated with each of the eight ISO service charges to obtain a total revenue requirement. This revenue requirement is allocated among the eight charges of the GMC through the application of the factors specified in Appendix F, Schedule 1, Part E of this Tariff.

The revenue requirement for each service then shall be divided by the forecast annual or periodic billing determinant volume to obtain a rate for each service, which will be payable by Scheduling Coordinators as set forth in Section 11.2.2.3. The rates so established will be adjusted annually, through the operation

of the formula set forth in Appendix F, Schedule 1, Part A of this Tariff. The ISO shall post on its website each year, before the adjusted rates go into effect, as described in Appendix F, Schedule 1,

Part D of this Tariff, data showing the rates adjusted to reflect any change in the annual revenue requirement, variance between forecast and actual costs for the previous year or period, or any surplus revenues from the previous year or period (as defined in Section 11.2.2.5), or the inability to recover from a Scheduling Coordinator its share of the Grid Management Charge, or any under-achievement of a forecast of the billing determinant volumes used to establish the rates. The circumstances under which the ISO is permitted to put the adjusted rates into effect without submitting a filing to the FERC are described in Appendix F, Schedule 1, Part D of this Tariff. Appendix F, Schedule 1, Part B of this Tariff sets forth the conditions under which a quarterly adjustment to the Grid Management Charge will be made.

11.2.2.4.1 Credits and Debits of the Grid Management Charge.

In addition to the adjustments permitted under Section 11.6.3.3, the ISO shall credit or debit, as appropriate, the account of a Scheduling Coordinator for any overpayment or underpayment of the Grid Management Charge that the ISO determines occurred due to error, omission, or miscalculation by the ISO or the Scheduling Coordinator.

11.2.2.5 Operating and Capital Reserves Account.

Revenues collected to fund the ISO financial operating reserves shall be deposited in an Operating and Capital Reserves Account until such account reaches a level specified by the ISO Governing Board. The Operating and Capital Reserves Account shall be calculated separately for each GMC service category (Core Reliability Services – Demand, Core Reliability Services – Energy Export, Energy Transmission Services – Net Energy, Energy Transmission Services – Uninstructed Deviations, Forward Scheduling, Congestion Management, Market Usage, and Settlements, Metering and Client Relations). The allocation factors, reassignments and reallocations specified in Schedule 1, Parts E and F, will be accounted for in the development of the Operating and Capital Reserves Account for each component. If

the Operating and Capital Reserves Account as calculated for such service category is fully funded, surplus funds will be considered an offset to the revenue requirement of the next fiscal year.

11.2.3 Ancillary Services.

The ISO shall calculate, account for and settle charges and payments for Ancillary Services as set out in Sections 8.11.1 to 8.11.3A, 8.12.1 to 8.12.3A of this Tariff and Part C of Appendix N.

11.2.4 Imbalance Energy.

The ISO shall calculate, Dispatch and account for Imbalance Energy for each Dispatch Interval and settle Imbalance Energy in the Real Time Market for each Settlement Interval for the relevant Zone or Scheduling Point within the ISO Controlled Grid. Imbalance Energy is the difference between the Metered Quantity and the Energy that corresponds to the Final Hour-Ahead Schedule. Instructed Imbalance Energy is the portion of Imbalance Energy that is produced or consumed due to Dispatch Instructions. The Instructed Imbalance Energy will be calculated based on all Dispatch Instructions taking into account applicable ramp rates and time delays. All Dispatch Instructions shall be deemed delivered. The remaining Imbalance Energy constitutes Uninstructed Imbalance Energy, and will be calculated based on the difference between the Metered Quantity and the Generator's Dispatched Operating Point.

11.2.4.1 Net Settlements for Uninstructed Imbalance Energy.

Uninstructed Imbalance Energy attributable to each Demand Take-Out Point, Generating Unit, System Unit or System Resource for which a Scheduling Coordinator has a Final Hour-Ahead Schedule or Metered Quantity, for each Settlement Interval, shall be deemed to be sold or purchased, as the case may be, by the ISO and charges or payments for Uninstructed Imbalance Energy shall be settled by debiting or crediting, as the case may be, the Scheduling Coordinator with an amount for each Settlement Interval in accordance with Section 34.9.2.1. Positive or negative Uninstructed Imbalance Energy as described in SABP Appendix D Section 2.1.1 shall be paid or charged the Resource-Specific Settlement Interval Ex Post Price or the Zonal Settlement Interval Ex Post Price, as the case may be.

11.2.4.1.1 Settlement for Instructed Imbalance Energy.

Instructed Imbalance Energy attributable to each Scheduling Coordinator in each Settlement Interval shall be deemed to be sold or purchased, as the case may be, by the ISO and charges or payments for Instructed Imbalance Energy shall be settled by debiting or crediting, as the case may be, the Scheduling Coordinator with an amount for each Settlement Interval in accordance with Section 34.9.

11.2.4.1.1.1 Bid Cost Recovery for Generating Units, System Units, Dynamically Scheduled System Resources, and Curtailable Demand.

The ISO shall determine, for each Trading Day, for each Generating Unit, System Unit, dynamically scheduled System Resource, and Curtailable Demand, Dispatched in the Real Time Market pursuant to Section 34.3.0, whether there exists a surplus or deficit in that resource's recovery of its Energy Bid costs, that are less than or equal to the Maximum Bid Level, through Instructed Imbalance Energy credits, as set forth in Section 11.2.4.1.1. This determination of market revenue surplus or deficit shall be calculated as the difference between: 1) the Instructed Imbalance Energy payment as based on the relevant Resource-Specific Settlement Interval Ex Post Price and 2) the resource's Energy Bid cost for each Settlement Interval. Bid cost recovery payment will be based on Settlement Intervals in which the resource: 1) did not recover its Energy Bid costs, and 2) generated or consumed an amount of Energy resulting from any Dispatch Instructions pursuant to Section 34.3.0. These Settlement Intervals will be netted against all Settlement Intervals in which the Instructed Imbalance Energy payments to the resource exceeded its Energy Bid costs. The resulting total bid cost recovery payment is then divided equally amongst the same Settlement Intervals to yield a per-Settlement Interval bid cost recovery payment. Payments for unrecovered bid costs for portions of Energy associated with bids above the Maximum Bid Level will not be netted with other surpluses or deficits and are subject to recall if the such bids above have not been adequately justified pursuant to Section 39.2. Energy Bid cost recovery associated with Residual Energy as provided for in Section 34.3.2.5 shall be based on the Energy Bids for the previous or next operating hour, whichever the case may be, upon which the Dispatch Instruction was based.

11.2.4.1.1.2 Bid Cost Recovery for System Resources.

The ISO shall settle predispached Energy from System Resources based on each resource's Energy Bid costs for each Settlement Interval, for each System Resource submitting bids in the Real Time Market pursuant to Section 8.2.2. This Energy bid cost settlement shall be calculated as set forth in Sections D 2.1.2 and D 2.6.3 in Part B of Appendix T. Bid cost settlement shall apply to both incremental and decremental predispached Energy.

An uplift payment will be made as necessary for each Settlement Interval to assure that the System Resource recovers its Energy Bid costs for the quantity of Energy delivered. Payments for un-recovered bid costs for portions of Energy associated with bids above the Maximum Bid Level are subject to recall if such bids have not been adequately justified pursuant to Section 39.2.

The settlement methodology set forth in this section will continue in effect until such time as the ISO implements a methodology for settling bids from System Resources as part of its Market Redesign and Technology Upgrade process.

11.2.4.1.2 Penalties for Uninstructed Imbalance Energy.

Effective December 1, 2004, the ISO shall not charge any Uninstructed Deviation Penalties pursuant to this Section 11.2.4.1.2 until FERC issues an order authorizing the ISO to charge Uninstructed Deviation Penalties pursuant to this section. Beginning with Settlement Statements for the first Trading Day for which FERC authorizes the ISO to charge Uninstructed Deviation Penalties pursuant to this section, the ISO shall charge Scheduling Coordinators Uninstructed Deviation Penalties for Uninstructed Imbalance Energy resulting from resource deviations outside a Tolerance Band from their Dispatch Operating Point, for dispatched resources, or their Final Hour-Ahead Schedule otherwise. The Dispatch Operating Point will take into account the expected Ramping of a resource as it moves to a new Hour-Ahead Schedule at the top of each hour and as it responds to Dispatch Instructions. The Uninstructed Deviation Penalty will be applied as follows:

- a) The Uninstructed Deviation Penalty for negative Uninstructed Imbalance Energy will be calculated and assessed in each Settlement Interval. The Uninstructed Deviation Penalty for

- positive Uninstructed Imbalance Energy will be calculated and assessed in each Settlement Interval in which the ISO has not declared a staged System Emergency;
- b) The Uninstructed Deviation Penalty will apply to pre-Dispatched bids from non-dynamically scheduled System Resources identified, when such a pre-Dispatch Instruction is issued more than 40 minutes prior to the relevant Operating Hour, subject to the following conditions: i) The Uninstructed Deviation Penalty will only apply to the pre-Dispatched amount of the bid that is declined or not delivered, ii) the Uninstructed Deviation Penalty will not apply to a portion of a pre-Dispatched bid that is subsequently not delivered at the direction of a Control Area, including the ISO, due to a curtailment of transmission capability or to prevent curtailment of native firm load occurring subsequent to issuing the pre-Dispatch Instruction, iii) the Uninstructed Deviation Penalty will not apply to uninstructed energy resulting from declining subsequent intra-hour Dispatch Instructions. Dynamically scheduled System Resources, to the extent they deviate from their Final Hour-Ahead Schedule plus any real-time Dispatch Instructions, will be subject to the Uninstructed Deviation Penalty;
 - c) The Uninstructed Deviation Penalty will not apply to Load or Curtailable Demand;
 - d) **[Not Used]**
 - e) The Uninstructed Deviation Penalty will not apply to Regulatory Must-Run Generation. No other applicable charges will be affected by this exemption. The Uninstructed Deviation Penalty also will not apply to Qualifying Facilities (QFs), including those that are dynamically scheduled, that have not executed a Participating Generator Agreement (PGA), pending resolution of QF-PGA issues at FERC;
 - f) For the Scheduling Coordinator of an MSS that has elected to follow the MSS Load and associated Transmission Losses pursuant to Section 4.9.9, the deviation penalties in Sections 4.9.9.2.1 and 4.9.9.2.2 will apply. For the Scheduling Coordinator of an MSS that has not elected to follow the MSS Load, the Uninstructed Deviation Penalties in this Section 11.2.4.1.2 will apply;

- g) The Uninstructed Deviation Penalty will apply to Generating Units providing Regulation and dynamically scheduled System Resources providing Regulation to the extent that uninstructed deviations from such resources exceed each resource's actual Regulation range plus the applicable Tolerance Band. Resources providing Regulation and generating within their relevant Regulating range (or outside their relevant Regulating range as a direct result of ISO control or instruction) will be deemed to have zero deviations for purposes of the Uninstructed Deviation Penalty.
- h) The Uninstructed Deviation Penalty will be calculated and assessed for each resource individually, except that as specified in Appendix R, uninstructed deviations from individual resources may be aggregated.
- i) **[Not Used]**
- j) **[Not Used]**
- k) The Uninstructed Deviation Penalty will not apply when the Zonal Settlement Interval Ex Post Price is negative or zero;
- l) The Uninstructed Deviation Penalty for positive Uninstructed Imbalance Energy will be the amount of the Uninstructed Imbalance Energy in excess of the Tolerance Band multiplied by a price equal to 100% of the corresponding Zonal Settlement Interval Ex Post Price. The net effect of the Uninstructed Deviation Penalty and the Settlement for positive Uninstructed Imbalance Energy beyond the Tolerance Band will be that the ISO will not pay for such Energy;
- m) The Uninstructed Deviation Penalty for negative Uninstructed Imbalance Energy will be the amount of the Uninstructed Imbalance Energy in excess of the Tolerance Band multiplied by a price equal to 50% of the corresponding Zonal Settlement Interval Ex Post Price;
- n) The Uninstructed Deviation Penalty will not apply to deviations from Energy delivered as part of a scheduled test so long as the test has been scheduled by the Scheduling Coordinator with the ISO or the ISO has initiated the test for the purposes of validating unit performance;

- o) The Uninstructed Deviation Penalty shall not apply to any excess Energy delivered from or any shortfall of Energy not delivered from an out-of-market (OOM) transaction involving a Generating Unit or a System Unit unless the ISO and the supplier have agreed upon the time of, duration of, and the amount of Energy to be delivered in the OOM transaction and the ISO reflects the OOM transaction in its real-time Expected Energy calculations. The Uninstructed Deviation Penalty shall apply to Energy outside the Tolerance Band from firm OOM transactions with dynamically scheduled System Resources to the extent the agreed-to Energy is not delivered or over-delivered, and to any Energy from non-dynamically scheduled System Resources to the extent the agreed-to Energy is not delivered if that over- or under-delivery was due to action taken by or not taken by the System Resource and not the result of action taken by a Control Area operator due to a curtailment of firm transmission capability or to prevent curtailment of native firm load occurring subsequent to the OOM transaction;
- p) Generating Units and dynamically scheduled System Resources with Uninstructed Imbalance Energy will be exempted from the Uninstructed Deviation Penalty if the Generating Unit or dynamically scheduled System Resource was physically incapable of delivering the expected Energy, provided that the Generating Unit or dynamically scheduled System Resource had notified the ISO within 30 minutes of the onset of an event that prevents the resource from performing its obligations. A Generating Unit or dynamically scheduled System Resource must notify ISO operations staff of its reasons for failing to deliver the expected Energy in accordance with Section 9.3.10.5 and must provide information to the ISO that verifies the reason the resource failed to comply with the Dispatch instruction within 48 hours of the operating hour in which the instruction is issued;
- q) **Adjustments to any Generating Unit, Curtailable Demand and System Resource Final Hour-Ahead Schedules made in accordance with the terms of Existing Contracts shall not be subject to Uninstructed Deviation Penalties.**
- r) Any changes made to Schedules prior to the ISO issuing Final Hour-Ahead Schedules shall not be subject to Uninstructed Deviation Penalties.**

- s) Uninstructed Deviation Penalties shall not be charged to any deviation from a Dispatch Instruction that does not comply with the requirements set forth in this ISO Tariff.
- t) Amounts collected as Uninstructed Deviation Penalties shall first be assigned to reduce the portion of above-MCP costs that would otherwise be assigned pro rata to all Scheduling Coordinators in that Settlement Interval pursuant to Section 11.2.4.2.2. Any remaining portion of amounts collected as Uninstructed Deviation Penalties after satisfying these sequential commitments shall be treated in accordance with Section 11.8.5.3.
- u) Condition 2 RMR Units shall be exempt from Uninstructed Deviation Penalties.
- v) The Uninstructed Deviation Penalty shall not apply to positive Uninstructed Imbalance Energy attributable to operation below the Generating Unit's minimum operating level from the time the Generating Unit synchronizes to the grid to the earlier of (1) the Settlement Interval in which the Generating Unit produces a quantity of Energy that represents an average rate of delivery over such Settlement Interval in excess of the Generating Unit's minimum operating level plus the applicable Tolerance Band, or (2) the first Settlement Interval after the expiration of a period of time that begins at the end of the Settlement Interval in which the Generating Unit synchronizes to the grid and ends after the Generating Unit's maximum start-up time as specified in the Master File. The Uninstructed Deviation Penalty shall not apply to any positive Uninstructed Imbalance Energy attributable to operation below the Generating Unit's minimum operating level for a duration equal to the time specified in the Generating Unit's Resource Data Template for the Generating Unit to disconnect from the grid after reaching its minimum operating level following either (1) the last Settlement Interval of an hour in which the Generating Unit had a non-zero Final Hour-Ahead Schedule or (2) the Settlement Interval in which the Generating Unit is expected to reach its minimum operating level based on the applicable ramp rate when the ISO instructed the Generating Unit to shut down. The amount of Uninstructed Imbalance Energy exempted from the Uninstructed Deviation Penalty shall not exceed the amount of the Generating Unit's minimum operating level plus the applicable Tolerance Band.

- (w) UDP shall not apply to deviations by a Generating Unit that are attributable to any automatic response to a system disturbance in accordance with Applicable Reliability Criteria.

11.2.4.2 Payment Options for ISO Dispatch Orders.

With respect to all resources which have not bid into the Imbalance Energy or Ancillary Services markets but which have been dispatched by the ISO to avoid an intervention in market operations, to prevent or relieve a System Emergency, or to satisfy a locational requirement, the ISO shall calculate, account for and, if applicable, settle deviations from the Final Schedule submitted on behalf of each such resource, with the relevant Scheduling Coordinator for each Settlement Period for each such resource by application of either of the following payment options described below. For resources subject to a Reliability Must-Run Contract, the ISO will dispatch such resources according to the terms of the RMR Contract, except as provided for below. In circumstances where an RMR Unit would be used to resolve Intra-Zonal Congestion and there are no such RMR Units available, a resource may be called upon and paid under this Section to resolve the Intra-Zonal Congestion.

By December 31 of each year for the following calendar year, each Scheduling Coordinator for a resource shall select one of the following payment options for each resource it schedules:

(a) the Uninstructed Imbalance Energy charge price as calculated in accordance with Section 34.9.2.4 (i.e., using the Hourly Ex Post Price) or

(b) a calculated price:

(i) for decremental dispatch orders that is an Energy payment to the ISO that is equal to the Market Clearing Price for the relevant Settlement Period for the applicable Energy market less verifiable daily gas imbalance charges, if any, that are solely attributable to the ISO's Dispatch Instruction and that the Scheduling Coordinator or Generator was not able to eliminate or reduce despite the application of best efforts, if the Scheduling Coordinator provides the resource's daily gas imbalance charges to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched; and

(ii) for incremental dispatch orders is the sum of: 1) a capacity payment equal to the average Day-Ahead Market prices for Spinning Reserve

and Non-Spinning Reserve for the three (3) most recent similar days for the same Settlement Period for which the resource is dispatched; 2) an Energy payment equal to the average calculated using the ISO Real Time Market Energy prices for the three (3) most recent similar days for the same Settlement Period for which the resource is dispatched; 3) such resource's verifiable Start-Up Costs, if the start-up was solely attributable to the ISO's Dispatch Instruction and if the Scheduling Coordinator provides the resource's Start-Up Costs to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched; and 4) verifiable daily gas imbalance charges, if any, that are solely attributable to the ISO's Dispatch Instruction and that the Scheduling Coordinator or Generator was not able to eliminate or reduce despite the application of best efforts, if the Scheduling Coordinator provides the resource's daily gas imbalance charges to the ISO within thirty (30) Business Days from the Settlement Period for which the resource is dispatched. References to "similar days" in this Section refer to Business Days when the resource is dispatched on a Business Day and otherwise to days that are not Business Days.

To the extent a Scheduling Coordinator does not specify a payment option, the ISO will apply the payment provisions of the payment option described in Section 11.2.4.2(a).

If the ISO Dispatches an RMR Unit that has selected Condition 2 of its RMR Contract to start-up or provide energy other than a start-up or energy requested pursuant to the RMR Contract, as provided in Section 5.2.9 of the ISO Tariff, the ISO shall pay as follows:

(a) if the Owner has elected Option A of Schedule G, two times the start-up cost specified in Schedule D to the applicable RMR Contract for any start-up incurred, and 1.5 times the rate specified in Equation 1a or 1b below times the amount of energy delivered in response to the ISO's instruction;

(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.

11.2.4.2.2 Allocation of Above-MCP Costs For Accepted Bids.

For each Settlement Interval, the at or below-MCP costs incurred as a result of accepted bids in the ISO Imbalance Energy Markets shall be allocated in accordance with 11.2.4.1. Allocation of above-MCP costs for accepted bids in the ISO Imbalance Energy Markets shall be in accordance with this Section 11.2.4.2.2 as follows.

11.2.4.2.2.1 Allocation of Bid Costs Above the Maximum Bid Level.

For each Settlement Interval, costs that are both above the MCP and above the Maximum Bid Level, incurred by the ISO as a result of Instructed Imbalance Energy and Dispatch instructions for reasons other than for a transmission facility Outage or a location-specific requirement shall be charged to Scheduling Coordinators as follows in a three-step process. First, each Scheduling Coordinator's charge shall be the lesser of:

(a) the pro rata share of the total costs that are both above the MCP and above the Maximum Bid Level based upon the ratio of each Scheduling Coordinator's Net Negative Uninstructed Deviations to the total system Net Negative Uninstructed Deviations; or

(b) the amount obtained by multiplying the Scheduling Coordinator's Net Negative Uninstructed Deviation for each Settlement Interval and a weighted average price. The weighted average price is equal to the total costs that are both above the MCP and above the Maximum Bid Level divided by the MWh delivered as a result of ISO instructions with a cost component above the MCP.

Second, any remaining unallocated costs shall be reduced pursuant to Section 11.2.4.1.2.

Third, any remaining unallocated costs shall be allocated amongst all Scheduling Coordinators in that Settlement Interval pro rata based on their metered Demand, including exports.

A Scheduling Coordinator shall be exempt from the first allocation step of costs that are both above the MCP and above the Maximum Bid Level in a Settlement Interval if the Scheduling Coordinator has sufficient incremental Energy bids from physically available resources in the Imbalance Energy market to

cover its Net Negative Uninstructed Deviation in the given Settlement Interval and the prices of such Energy bids do not exceed the applicable **Maximum Bid Level as set forth in Section 39.2 of this Tariff.**

11.2.4.2.2 Allocation of Bid Costs Above-MCP and Below the Maximum Bid Level.

For each Settlement Interval, the total unrecovered costs pursuant to Section 11.2.4.1.1.1 that are above the MCP and below the Maximum Bid Level for each Trading Day will be allocated pro-rata to each Scheduling Coordinator based on its metered Demand. For a Scheduling Coordinator of an MSS Operator that has elected to follow Load, allocation of such unrecovered costs will be based on net metered Demand.

11.2.4.3 Unaccounted For Energy (UFE).

For settlement purposes, UFE is treated as Imbalance Energy. For each Settlement Interval, the ISO will calculate UFE on the ISO Controlled Grid, for each utility Service Area for which separate UFE calculation is performed. The UFE will be settled as Imbalance Energy at the Zonal Settlement Interval Ex Post Price. UFE attributable to meter measurement errors, load profile errors, Energy theft, and distribution loss deviations will be allocated to each Scheduling Coordinator based on the ratio of their metered Demand (including exports to neighboring Control Areas) within the relevant utility Service Area to total metered Demand within the utility Service Area.

11.2.4.4 High Voltage Access Charge.

High Voltage Access Charges and Transition Charges will be levied in accordance with Section 26.1 of this ISO Tariff and Appendix F, Schedule 3.

11.2.4.5 Participating Intermittent Resources.

11.2.4.5.1 Uninstructed Energy and Transmission Losses by Participating Intermittent Resources.

Uninstructed Imbalance Energy associated with deviations by a Participating Intermittent Resource and Transmission Losses shall be settled as provided in this Section 11.2.4.5.1 for every Settlement Period in which such Participating Intermittent Resource meets the scheduling requirements established in the

Appendix Q. In each Settlement Period such requirements are met, the Participating Intermittent Resource shall be exempt from the Uninstructed Deviation Penalty that otherwise would be determined in accordance with Section 11.2.4.1.2 and other charges (payments) for Uninstructed Imbalance Energy. Instead, the net Uninstructed Imbalance Energy in each Settlement Interval, together with the transmission loss obligation calculated in accordance with Section 27.2.1.1.1, shall be assigned to a deviation account specific to each Participating Intermittent Resource. The net balance in each deviation account at the end of each calendar month shall be paid (or charged) to the Scheduling Coordinator for the associated Participating Intermittent Resource at the average price specified in Section 34.9.2.5 of the ISO Tariff. If the above-referenced scheduling requirements for Participating Intermittent Resources are not met, then charges (payments) for Uninstructed Imbalance Energy during such Settlement Periods shall be determined in accordance with Section 11.2.4.1.

11.2.4.5.2 Adjustment of Other Charges Related to Participating Intermittent Resources.

Charges pursuant to Section 8.12.3A or Section 11.2.4.2.2 to Scheduling Coordinators representing Participating Intermittent Resources shall exclude the effect of uninstructed deviations by Participating Intermittent Resources that have scheduled in accordance with the ISO Protocols. The amount of such adjustments shall be accumulated and settled as provided in Section 11.2.4.5.3.

11.2.4.5.3 Allocation of Costs From Participating Intermittent Resources.

The charges (payments) for Uninstructed Imbalance Energy that would have been calculated if the Settlement Interval deviations by each Participating Intermittent Resource were priced at the appropriate Dispatch Interval Ex Post Price shall be assigned to a monthly balancing account for all Participating Intermittent Resources in the ISO Control Area. The balance in such account at the end of each month shall be netted against the aggregate payments (charges) by Scheduling Coordinators on behalf of Participating Intermittent Resources pursuant to Section 11.2.4.5.1. The resulting balance, together with the adjustments to charges in each Settlement Interval or Settlement Period pursuant to Section 11.2.4.5.2 shall be assigned to each Scheduling Coordinator in the same proportion that such Scheduling

Coordinator's aggregate Net Negative Uninstructed Deviations in that month bears to the aggregate Net Negative Uninstructed Deviations for all Scheduling Coordinators in the Control Area in that month.

11.2.4.5.4 Payment of Participating Intermittent Resource Fees

11.2.4.5.4.1 Forecasting Fee

A fee to defray the costs of the implementation of the forecasting service for Participating Intermittent Resources shall be assessed to Scheduling Coordinators for Participating Intermittent Resources as specified in Schedule 4 of Appendix F.

11.2.4.5.4.2 Process Fee

A fee to defray the costs of processing the Participating Intermittent Resource Export Fee as specified in Schedule 4 of Appendix F.

11.2.4.5.4.3 Participating Intermittent Resource Export Fee

A Participating Intermittent Resource Export Fee will be levied in accordance with Section 5.3 of Appendix Q and Schedule 4 of Appendix F.

11.2.4.6 [Not Used]

11.2.5 Usage Charges.

Usage Charges will be levied in accordance with Section 27.1.2.1 and Appendix N, Part E of this Tariff.

11.2.6 Wheeling Through and Wheeling Out Transactions.

The ISO shall calculate, account for and settle charges and payments for Wheeling Through and Wheeling Out transactions in accordance with Section 26.1.4 and Appendix N, Part C of this Tariff.

11.2.7 Voltage Support and Black Start Charges.

The ISO shall calculate, account for and settle charges and payments for Voltage Support and Black Start as set out in Sections 8.11.4, 8.11.5, 8.12.4, 8.12.5, and the SABP Charge Computation Manual – Appendix N, Part G of this ISO Tariff.

11.2.8 Reliability Must-Run Charges.

The ISO shall calculate and levy the charges for Reliability Must-Run Contract costs in accordance with Section 30.6.1.1 of this ISO Tariff.

11.2.9 Neutrality Adjustments.

The ISO shall be authorized to levy additional charges or payments as special adjustments in regard to:

- (a) amounts required to round up any invoice amount expressed in dollars and cents to the nearest whole dollar amount in order to clear the ISO Clearing Account. These charges will be allocated amongst Scheduling Coordinators over an interval determined by the ISO and pro rata based on metered Demand (including exports) during that interval;

(b) amounts in regard to penalties or sanctions which may be levied by the ISO in accordance with the ISO Tariff. These charges will be levied on the Market Participants liable for payment of the penalty or sanction;

(c) amounts required to reach an accounting trial balance of zero in the course of the Settlement process in the event that the charges calculated as due from ISO Debtors are lower than payments calculated as due to the ISO Creditors for the same Trading Day. These charges will be allocated amongst the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (including exports) in MWh of Energy for that Trading Day. In the event that the charges due from ISO Debtors are higher than the payments due to ISO Creditors, the ISO shall allocate a payment to the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (including exports) in MWh of Energy for that Trading Day;

(d) amounts required with respect to payment adjustments for regulating Energy as calculated in accordance with Section 8.11.1. These charges will be allocated amongst the Scheduling Coordinators who traded on that Trading Day pro rata to their metered Demand (excluding exports) in MWh for that Trading Day; and

(e) awards payable by or to the ISO pursuant to good faith negotiations or ISO ADR Procedures that the ISO is not able to allocate to or to collect from a Market Participant or Market Participants in accordance with Section 13.5.3. These charges will be allocated amongst Scheduling Coordinators over an interval determined by the ISO and pro rata based on metered Demand (including exports) during that interval.

11.2.9.1 The total annual charges levied under Section 11.2.9 shall not exceed \$0.095/MWh, applied to Gross Loads in the ISO Control Area and total exports from the ISO Controlled Grid, unless: (a) the ISO Governing Board reviews the basis for the charges above that level and approves the collection of charges above that level for a defined period; and (b) the ISO provides at least seven days' advance notice to Scheduling Coordinators of the determination of the ISO Governing Board.

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).

11.2.19 NERC/WECC Charges

11.2.19.1 Responsibility for NERC/WECC Charges

- (a) The ISO shall invoice Scheduling Coordinators for all of the NERC/WECC Charges that are invoiced to the ISO by the WECC on behalf of itself, NERC, and/or regional advisory bodies. Each Scheduling Coordinator shall be obligated to pay the ISO all of the

NERC/WECC Charges it is invoiced by the ISO in accordance with this Section 11.2.19. Each Scheduling Coordinator's responsibility for NERC/WECC Charges is based on the Scheduling Coordinator's NERC/WECC Metered Demand.

- (b) The ISO's calculation of collateral requirements and other credit requirements under the ISO Tariff will not include any adjustment for a Scheduling Coordinator's NERC/WECC Charges.

11.2.19.2 Process for Invoicing NERC/WECC Charges Assessed for 2007.

With regard to the NERC/WECC Charges assessed by the WECC for 2007, the following process shall apply:

- (a) The ISO will issue a market notice that will include the following: (i) the total NERC/WECC Charges for 2007 that were invoiced to the ISO by the WECC and (ii) the total of all Scheduling Coordinators' NERC/WECC Metered Demand for 2005. On or after the date on which the ISO issues this market notice, the ISO will notify each Scheduling Coordinator in writing of the Scheduling Coordinator's NERC/WECC Metered Demand for 2005. Each Scheduling Coordinator shall have sixty (60) Calendar Days from the date the ISO provides it with this notification in writing to raise any disputes concerning the ISO's calculation of the Scheduling Coordinator's NERC/WECC Metered Demand for 2005.
- (b) The ISO will issue a market notice setting forth the Final NERC/WECC Charge Rate for the 2007 WECC assessment. The Final NERC/WECC Charge Rate for the 2007 WECC assessment shall be based on (i) the total NERC/WECC Charges for 2007 that were invoiced to the ISO by the WECC divided by (ii) the total of all Scheduling Coordinators' NERC/WECC Metered Demand for 2005, including any adjustments to the calculation of NERC/WECC Metered Demand for 2005 made by the ISO in response to disputes raised by Scheduling Coordinators pursuant to Section 11.2.19.2(a).

- (c) Within thirty (30) Calendar Days after the ISO issues the market notice in Section 11.2.19 (b), the ISO will issue Final NERC/WECC Charge Invoices that allocate NERC/WECC Charges for 2007 to Scheduling Coordinators based on (i) each Scheduling Coordinator's NERC/WECC Metered Demand for 2005 multiplied by (ii) the Final NERC/WECC Charge Rate for the 2007 WECC assessment. The ISO shall deduct from the Final NERC/WECC Charge Invoices for the 2007 WECC assessment any amounts that Scheduling Coordinators have already paid directly to the WECC for NERC/WECC Charges for 2007 as reported to the ISO by the WECC.

11.2.19.3 Process for Invoicing NERC/WECC Charges Assessed for 2008.

With regard to the NERC/WECC Charges to be assessed by the WECC for 2008, the following process shall apply:

- (a) The ISO will issue a market notice that will include the total of all Scheduling Coordinators' NERC/WECC Metered Demand for 2006. On or after the date on which the ISO issues this market notice, the ISO will notify each Scheduling Coordinator in writing of the Scheduling Coordinator's NERC/WECC Metered Demand 2006. Each Scheduling Coordinator shall have sixty (60) Calendar Days from the date the ISO provides it with this notification in writing to raise any disputes concerning the ISO's calculation of the Scheduling Coordinator's NERC/WECC Metered Demand for 2006.
- (b) The ISO will report to the WECC the total of all Scheduling Coordinators' NERC/WECC Metered Demand for 2006, including any adjustments to the calculation of NERC/WECC Metered Demand for 2006 made by the ISO in response to disputes raised by Scheduling Coordinators pursuant to Section 11.2.19.3(a). This report shall facilitate the WECC calculation of actual NERC/WECC Charges to be invoiced to the ISO for 2008.

- (c) Within five (5) Business Days after receipt of the WECC invoice to the ISO setting forth the assessment for NERC/WECC Charges 2008, the ISO shall issue a market notice setting forth the Final NERC/WECC Charge Rate for the 2008. The Final NERC/WECC Charge Rate for the 2008 shall be based on (i) the total NERC/WECC Charges for 2008 that were invoiced to the ISO by the WECC, divided by (ii) the total of all Scheduling Coordinators' NERC/WECC Metered Demand for 2006, as reported to the WECC.

- (d) Within fifteen (15) Business Days after receipt of the WECC invoice to the ISO setting forth the assessment for NERC/WECC Charges for 2008, the ISO will issue Final NERC/WECC Charge Invoices that allocate NERC/WECC Charges for 2008 to Scheduling Coordinators based on (i) each Scheduling Coordinator's NERC/WECC Metered Demand for 2006, multiplied by (ii) the Final NERC/WECC Charge Rate for 2008.

11.2.19.4 Process for Invoicing NERC/WECC Charges Assessed for Years After 2008.

With regard to the NERC/WECC Charges to be assessed by the WECC for each NERC/WECC Charge Assessment Year after 2008, the following processes shall apply:

- (a) The ISO will issue a market notice that will include the total of all Scheduling Coordinators' NERC/WECC Metered Demand for the calendar year two years prior to the NERC/WECC Charge Assessment Year. On or after the date on which the ISO issues this market notice, the ISO will notify each Scheduling Coordinator in writing of the Scheduling Coordinator's NERC/WECC Metered Demand for the calendar year two years prior to the NERC/WECC Charge Assessment Year. Each Scheduling Coordinator shall have sixty (60) Calendar Days from the date the ISO provides it with this notification in writing to raise any disputes concerning the ISO's calculation of the Scheduling Coordinator's NERC/WECC Metered Demand for the calendar year two years prior to the NERC/WECC Charge Assessment Year.
- (b) The ISO will report to the WECC the total of all Scheduling Coordinators' NERC/WECC Metered Demand for the calendar year two years prior to the NERC/WECC Charge Assessment Year, including any adjustments to the calculation of NERC/WECC Metered Demand for that year made by the ISO in response to disputes raised by Scheduling Coordinators pursuant to Section 11.2.19.4(a). The report will also include any adjustments to the calculation of NERC/WECC Metered Demand, based on decisions by the WECC to permit such adjustments, that the ISO has time to reflect in the report and that the WECC provides to the ISO in a written statement in accordance with the ISO-WECC Billing Services Agreement. This report shall facilitate the WECC's calculation of actual NERC/WECC Charges to be invoiced to the ISO for the NERC/WECC Charge Assessment Year.

- (c) The ISO will issue a market notice setting forth the Preliminary NERC/WECC Charge Rate for the NERC/WECC Charge Assessment Year.
- (d) By August 31 of the year preceding the NERC/WECC Charge Assessment Year, the ISO will issue Preliminary NERC/WECC Charge Invoices for the NERC/WECC Charge Assessment Year.
- (e) Within five (5) Business Days after receipt of the WECC's invoice to the ISO setting forth the assessment of NERC/WECC Charges for the NERC/WECC Charge Assessment Year, the ISO shall issue a market notice setting forth the Final NERC/WECC Charge Rate for the NERC/WECC Charge Assessment Year. The Final NERC/WECC Charge Rate for the NERC/WECC Charge Assessment Year shall be based on (i) the total NERC/WECC Charges for the NERC/WECC Charge Assessment Year that were invoiced to the ISO by the WECC, divided by (ii) the total of all Scheduling Coordinators' NERC/WECC Metered Demand including any adjustments to the calculation of NERC/WECC Metered Demand as reported to the WECC pursuant to Section 11.2.19.4(b), and including any additional adjustments to the calculation of NERC/WECC Metered Demand, based on decisions by the WECC to permit such adjustments, that the WECC provides to the ISO in a written statement in accordance with the ISO-WECC Billing Services Agreement.

- (f) Within fifteen (15) Business Days after receipt of the WECC invoice to the ISO setting forth the assessment for NERC/WECC Charges for the NERC/WECC Charge Assessment Year, the ISO will issue Final NERC/WECC Charge Invoices that allocate NERC/WECC Charges for the NERC/WECC Charge Assessment Year to Scheduling Coordinators based on (i) each Scheduling Coordinator's NERC/WECC Metered Demand as adjusted pursuant to Sections 11.2.19.4(b) and 11.2.19.4(e) and pursuant to any additional adjustments that the WECC provides to the ISO in a written statement in accordance with the ISO-WECC Billing Services Agreement, multiplied by (ii) the Final NERC/WECC Charge Rate for the NERC/WECC Charge Assessment Year. If and to the extent that a Scheduling Coordinator has not already paid all of the NERC/WECC Charges for the NERC/WECC Charge Assessment Year that it is required to pay, the Scheduling Coordinator's Final NERC/WECC Charge Invoice will show the amount the Scheduling Coordinator is still required to pay. If and to the extent that a Scheduling Coordinator has already paid in excess of the NERC/WECC Charges for the NERC/WECC Charge Assessment Year that the Scheduling Coordinator is required to pay, the Scheduling Coordinator's Final NERC/WECC Charge Invoice will show the amount the Scheduling Coordinator will be credited.

11.2.19.5 Timely Payments.

Scheduling Coordinators shall make timely payments to the ISO pursuant to Preliminary NERC/WECC Charge Invoices within thirty (30) Calendar Days of issuance of such invoices. Scheduling Coordinators shall make timely payments to the ISO pursuant to Final NERC/WECC Charge Invoices within fifteen (15) Business Days of issuance of such invoices.

11.2.19.6 NERC/WECC Charge Trust Account.

The ISO shall deposit all payments received pursuant to Preliminary NERC/WECC Charge Invoices and Final NERC/WECC Charge Invoices in the NERC/WECC Charge Trust Account. The NERC/WECC Charge Trust Account shall be 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 NERC/WECC Charge Trust Account in order to pay the WECC any and all NERC/WECC Charges invoiced to the ISO.

11.2.19.7 Preliminary NERC/WECC Charge Invoices and Final NERC/WECC Charge Invoices.

The ISO shall invoice NERC/WECC Charges to Scheduling Coordinators by issuing Preliminary NERC/WECC Charge Invoices and Final NERC/WECC Charge Invoices. The Preliminary NERC/WECC Charge Invoices and Final NERC/WECC Charge Invoices shall be issued in accordance with the schedules set forth in this Section 11.2.19, provided that the ISO may issue a market notice informing Scheduling Coordinators that the ISO will implement a temporary modification to that schedule and setting forth the reasons for such modification, in which case the modified schedule described in that market notice shall govern.

11.2.19.7.1 Confirmation.

It is the responsibility of each Scheduling Coordinator to notify the ISO if the Scheduling Coordinator fails to receive a Preliminary NERC/WECC Charge Invoice or a Final NERC/WECC Charge Invoice in accordance with the applicable schedule. Each Scheduling Coordinator shall be deemed to have received its Preliminary NERC/WECC Charge Invoice or Final NERC/WECC Charge Invoice on the date specified in the applicable schedule, unless the Scheduling Coordinator notifies the ISO to the contrary.

11.2.19.7.2 Validation.

Each Scheduling Coordinator shall have the opportunity to review the terms of the Preliminary NERC/WECC Charges Invoices and the Final NERC/WECC Charge Invoices that it receives. The Scheduling Coordinator shall be deemed to have validated each Preliminary NERC/WECC Charge Invoice or Final NERC/WECC Charge Invoice unless it has raised a dispute within ten (10) Calendar Days from the date of issuance. Once validated, a Preliminary NERC/WECC Charge Invoice or Final NERC/WECC Charge Invoice shall be binding on the Scheduling Coordinator to which it relates.

11.2.19.6.3 Disputes and Dispute-Related Corrections.

11.2.19.7.3 Disputes and Dispute-Related Corrections.

Scheduling Coordinators shall be prohibited from disputing any Preliminary NERC/WECC Charge Invoice or Final NERC/WECC Charge Invoice, except on grounds that an error in a Preliminary NERC/WECC Charge Invoice or Final NERC/WECC Charge Invoice is due to a mere typographical or other ministerial error by the ISO. A Scheduling Coordinator that wishes to dispute a NERC/WECC Charge Invoice on such grounds shall give the ISO notice of dispute in writing within ten (10) Calendar Days of issuance. The notice of dispute shall state clearly the issue date of the Preliminary NERC/WECC Charge Invoice or Final NERC/WECC Charge Invoice, the item or calculation disputed, and the reasons for the dispute, and shall be accompanied by all available evidence reasonably required to support the claim. If the Scheduling Coordinator is correct that the Preliminary NERC/WECC Charge Invoice or Final NERC/WECC Charge Invoice contains a typographical or other ministerial error and the resolution of the dispute makes correction necessary, the ISO shall issue a corrected Preliminary NERC/WECC Charge Invoice or a corrected Final NERC/WECC Charge Invoice within fifteen (15) Calendar Days of issuance of the invoice that is being corrected.

Each Scheduling Coordinator that receives a Preliminary NERC/WECC Charge Invoice or a Final NERC/WECC Charge Invoice shall pay any net debit and shall be entitled to receive any net credit in a Preliminary NERC/WECC Charge Invoice or a Final NERC/WECC Charge Invoice on the Payment Date, regardless of whether there is any dispute regarding the amount of the debit or credit. The ISO will issue corrected Preliminary NERC/WECC Charge Invoices or corrected Final NERC/WECC Charge Invoices if the resolution of a dispute concerning a Preliminary NERC/WECC Charge Invoice or a Final NERC/WECC Charge Invoice, brought pursuant to this Section 11.2.19, makes such a correction necessary.

11.2.19.8 Provision of Payments and Information to the WECC.

- (a) With regard to NERC/WECC Charges assessed for 2007, the ISO will forward to the WECC, within five (5) Business Days after the deadline for timely payments of Final NERC/WECC Charge Invoices pursuant to Section 11.2.19.2 has expired, (i) the amounts collected pursuant to Final NERC/WECC Charge Invoices for 2007 and (ii) a list of all Scheduling Coordinators that have failed to make full payment pursuant to their Final NERC/WECC Charge Invoices and the amounts that are unpaid.
- (b) With regard to NERC/WECC Charges assessed for years after 2007, the ISO will forward to the WECC, at least three (3) Business Days prior to January 2 of each NERC/WECC Charge Assessment Year, (i) the amounts collected pursuant to Final NERC/WECC Charge Invoices for the NERC/WECC Charge Assessment Year and (ii) a list of all Scheduling Coordinators that have failed to make full payment pursuant to their NERC/WECC Charge Invoices and the amounts that are unpaid.
- (c) Under no circumstances shall the ISO be obligated to pay to the WECC, NERC or any regional advisory body, or to their successors or assignees, any NERC/WECC Charges or any interest charges related to NERC/WECC Charges except for those NERC/WECC Charges actually paid to the ISO by Scheduling Coordinators. The ISO shall have no obligations whatsoever to pursue collections of NERC/WECC Charges other than the obligation to invoice Scheduling Coordinators and to provide information to the WECC or NERC as provided for in the ISO Tariff. Notwithstanding the foregoing, the ISO shall have the right, at its sole discretion, to recoup, set off and apply any amount to which a Scheduling Coordinator is or will be entitled, in or towards the satisfaction of any of that Scheduling Coordinator's past-due NERC/WECC Charges in accordance with Section 11.12.4.

- (d) The ISO shall, on request, certify in writing the NERC/WECC Charges owed by a Scheduling Coordinator that remain unpaid and shall provide certified copies of the relevant Preliminary NERC/WECC Charge Invoices, Final NERC/WECC Charge Invoices, and other documentation on which the ISO's certificate was based to the WECC, NERC, and the applicable Scheduling Coordinators. An ISO certificate given under this Section 11.2.19.8(d) may be used as prima facie evidence of the amount due in any legal proceedings.

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

charge by or to that Scheduling Coordinator, Black Start Generator or Participating TO for each charge for that Trading Day. Each of these amounts will appear in the Preliminary and Final Settlement Statements that the ISO will provide to the relevant Scheduling Coordinator, Black Start Generator or Participating TO.

The eight components of the Grid Management Charge will be included in the Preliminary Settlement Statement and Final Settlement Statement with the other types of charges referred to in Section 11.2, but a separate invoice for the Grid Management Charge, stating the rate, billing determinant volume, and total charge for each of its eight components, will be issued by the ISO to the Scheduling Coordinator.

11.3.1 The billing and payment process shall be based on the issuance of Preliminary and Final Settlement Statements for each Settlement Period in each Trading Day.

11.3.2 Payment for the charges referred to in Section 11.1.6 of the ISO Tariff (except for the charges payable under long-term contracts) for each Trading Day in each calendar month shall be made five (5) Business Days after issuance of the Preliminary Settlement Statement for the last day of the relevant calendar month. Payment for adjustments will be made five (5) Business Days after issuance of the Final Settlement Statement for the last day of the relevant month. Payments for FERC Annual Charges will be made in accordance with Section 17 of this ISO Tariff.

11.3.3 Prepayments.

(a) A Scheduling Coordinator may choose to pay at an earlier date than the Payment Date specified in the ISO Payments Calendar by way of prepayment provided it notifies the ISO by electronic means before submitting its prepayment.

(b) Prepayment notifications must specify the dollar amount prepaid.

(c) Prepayments must be made by Scheduling Coordinators via Fed-Wire into their ISO prepayment account designated by the ISO. The relevant Scheduling Coordinator shall grant the ISO a security interest on all funds in its ISO prepayment account.

(d) On any Payment Date the ISO shall be entitled to cause funds from the relevant Scheduling Coordinator's ISO prepayment account to be transferred to the ISO Clearing Account in such amounts as may be necessary to discharge in full that Scheduling Coordinator's payment obligation arising in relation to that Payment Date.

(e) Any funds held in the relevant Scheduling Coordinator's ISO prepayment account shall be treated as part of that Scheduling Coordinator's Security.

(f) Interest (or other income) accruing on the relevant Scheduling Coordinator's ISO prepayment account shall inure to the benefit of that Scheduling Coordinator and shall be added to the balance of its ISO prepayment account on a monthly basis.

(g) Funds held in an ISO prepayment account by a Scheduling Coordinator may be recouped, offset or applied by the ISO to any outstanding financial obligations of that Scheduling Coordinator to the ISO or to other Scheduling Coordinators under this ISO Tariff,

11.3.4 System Failure.

11.3.4.1 At ISO Debtor's Bank.

If any ISO Debtor becomes aware that a payment will not, or is unlikely to be, remitted to the ISO Bank by 10:00 am on the relevant Payment Date for any reason (including failure of the Fed-Wire or any computer system), it shall immediately notify the ISO, giving full details of the payment delay (including the reasons for the payment delay). The ISO Debtor shall make all reasonable efforts to remit payment as soon as possible, by an alternative method if necessary, to ensure that funds are received for value no later than 10:00 am on the Payment Date, or as soon as possible thereafter.

11.3.4.2 At the ISO's Bank.

In the event of failure of any electronic transfer system affecting the ISO Bank, the ISO shall use reasonable efforts to establish alternative methods of remitting funds to the ISO Creditors' Settlement Accounts by close of banking business on that Payment Date, or as soon as possible thereafter. The ISO

shall notify the ISO Debtors and the ISO Creditors of occurrence of the system failure and the alternative methods and anticipated time of payment.

11.4 General Principles for Production of Settlement Statements.

11.4.1 Basis of Settlement.

The basis of each Settlement Statement shall be the debiting or crediting of an account in the name of the relevant Scheduling Coordinator in the general ledger set up by the ISO to reflect all transactions, charges or payments settled by the ISO.

11.4.2 Right to Dispute.

All Scheduling Coordinators shall have the right to dispute any item or calculation set forth in any Preliminary Settlement Statement in accordance with this ISO Tariff.

11.4.3 Data Files.

Settlement Statements relating to each Scheduling Coordinator shall be accompanied by a data file of supporting information that includes the following for each Settlement Period of the Trading Day on a Zone-by-Zone basis:

- (a) the aggregate quantity (in MWh) of Energy supplied or withdrawn by the Metered Entities represented by the Scheduling Coordinator;
- (b) the aggregate quantity (in MW) and type of Ancillary Services capacity provided or purchased;
- (c) the relevant prices that the ISO has applied in its calculations;
- (d) details of the Scheduled quantities of Energy and Ancillary Services accepted by the ISO in the Day-Ahead Market and the Hour-Ahead Market;
- (e) details of Imbalance Energy and penalty payments; and
- (f) detailed calculations of all fees, charges and payments allocated amongst Scheduling Coordinators and each Scheduling Coordinator's share.

11.4.4 Settlement Software.

The ISO Settlement software shall be audited by an independent firm of auditors competent to carry out audits of such software to determine its consistency with the ISO Tariff. In any dispute regarding Settlement calculations, a certificate of such firm of auditors that the ISO software is consistent with the ISO Tariff shall be prima facie proof that the charges shown in a Settlement Statement have been calculated in a method consistent with the ISO Tariff. Nothing in this section will be deemed to establish the burden of proof with respect to Settlement calculations in any proceeding.

11.5 Calculation in the Event of Lack of Meter Data for the Balancing of Market Accounts.

Settlements shall not be cleared for final processing until the accounting trial balance is zero. In order to publish a Settlement Statement, the ISO may use estimated, disputed or calculated Meter Data. When actual verified Meter Data is available and all of the disputes raised by Scheduling Coordinators during the validation process described in Section 11.7 of this ISO Tariff have been determined, the ISO shall recalculate the amounts payable and receivable by the affected Scheduling Coordinators or by all Scheduling Coordinators, if applicable, as soon as reasonably practical and shall show any required adjustments as a debit or credit in the next Settlement Statement.

11.6 Settlements Cycle.

11.6.1 Timing of the Settlements Process.

11.6.1.1 Preliminary Statements.

The ISO shall provide to each Scheduling Coordinator, Black Start Generator or Participating TO for validation a Preliminary Settlement Statement for each Trading Day within thirty-eight (38) Business Days of the relevant Trading Day, covering all Settlement Periods in that Trading Day. Each Preliminary Settlement Statement will include a statement of:

- (a) the amount payable or receivable by the Scheduling Coordinator, Black Start Generator or Participating TO for each charge referred to in Section 11.2 for each Settlement Period in the relevant Trading Day;
- (b) the total amount payable or receivable by that Scheduling Coordinator, Black Start Generator or Participating TO for each charge for all Settlement Periods in that Trading Day after the amounts payable and the amounts receivable under (a) have been netted off pursuant to Section 11.3; and
- (c) the components of each charge in each Settlement Period except for information contained in the Imbalance Energy Report referred to in Section 11.6.1.1.

Each Preliminary Settlement Statement shall also be accompanied by a breakdown of the components of the Imbalance Energy Charge (the "Imbalance Energy Report").

11.6.1.2 Each Scheduling Coordinator, Black Start Generator or Participating TO shall have a period of eight (8) Business Days from the issuance of a Preliminary Settlement Statement during which it may review the Preliminary Settlement Statement and notify the ISO of any errors. No later than fifty-one (51) Business Days after the Trading Day to which it relates, the ISO shall issue a Final Settlement Statement to each Scheduling Coordinator for that Trading Day.

11.6.1.2A Final Statements.

The ISO shall provide to each Scheduling Coordinator, Black Start Generator or Participating TO a Final Settlement Statement in accordance with the ISO Tariff and the ISO Payments Calendar. The Final Settlement Statement shall be in a format similar to that of the Preliminary Settlement Statement and shall include all the information provided in the Preliminary Settlement Statement as amended following the validation procedure.

11.6.1.3 Each Scheduling Coordinator, Black Start Generator or Participating TO shall have a period of ten (10) Business Days from the issuance of the Final Settlement Statement during which it may

review the Incremental Changes on the Final Settlement Statement and notify the ISO of any errors. No later than twenty-five (25) Business Days from the date of issuance of the Final Settlement Statement, the ISO shall incorporate any required corrections in a subsequent Preliminary Settlement Statement.

11.6.2 Basis for Billing and Payment.

The Preliminary and the Final Settlement Statements shall constitute the basis for billing and associated automatic funds transfers in accordance with this ISO Tariff. The Preliminary Settlement Statement shall constitute the basis for billing and associated automatic funds transfers for all charges in the first instance. The Final Settlement Statement shall constitute the basis for billing and associated automatic funds transfers for adjustments to charges set forth in the Preliminary Settlement Statement. Each Scheduling Coordinator shall pay any net debit and shall be entitled to receive any net credit shown in an invoice on the Payment Date, whether or not there is any dispute regarding the amount of the debit or credit.

11.6.2.1 Elimination of Invoices under \$10.00.

Preliminary and final invoices either due to or from any Market Participant for amounts less than \$10.00 will be adjusted to \$0.00 and no amount will be due to or from that Market Participant for that invoice.

11.6.3 Settlement Statement Re-runs and Post Final Adjustments.

The ISO is authorized to perform Settlement Statement Re-runs following approval of the ISO Governing Board. A request to perform a Settlement Statement Re-run may be made at any time by a Scheduling Coordinator by notice in writing to the ISO Governing Board. The ISO Governing Board shall, in considering whether to approve a request for a Settlement Statement Re-run, determine in its reasonable discretion, whether there is good cause to justify the performance of a Settlement Statement Re-run.

11.6.3.1 If a Settlement Statement Re-run is ordered by the ISO Governing Board, the ISO shall arrange to have the Settlement Statement Re-run carried out as soon as is reasonably practicable following the ISO Governing Board's order, subject to the availability of staff and computer time, compatible software, appropriate data and other resources.

11.6.3.2. The cost of a Settlement Statement Re-run shall be borne by the Scheduling Coordinator requesting it, unless the Settlement Statement Re-run was needed due to a clerical oversight or error on the part of the ISO staff.

11.6.3.3 Where a Settlement Statement Re-run indicates that the accounts of Scheduling Coordinators should be debited or credited to reflect alterations to Settlements previously made under this ISO Tariff, for those Scheduling Coordinators affected by the statement re-run, the ISO shall reflect the amounts to be debited or credited in the next Preliminary Settlement Statements that it issues following the Settlement Statement Re-run to which the provisions of this Section 11 apply.

11.6.3.4 Reruns, post closing adjustments and the financial outcomes of Dispute Resolution may be invoiced separately from monthly market activities. The ISO shall provide a market notice at least 30 days prior to such invoicing identifying the components of such invoice.

11.7 Confirmation and Validation.

11.7.1 Confirmation.

It is the responsibility of each Scheduling Coordinator to notify the ISO if it fails to receive a Preliminary Settlement Statement or a Final Settlement Statement on the date specified for the publication of such Settlement Statement in the ISO Payments Calendar. Each Scheduling Coordinator shall be deemed to have received its Settlement Statement on the dates specified, unless it notifies the ISO to the contrary.

11.7.2 Validation.

Each Scheduling Coordinator, Black Start Generator, or Participating TO shall have the opportunity to review the terms of the Preliminary Settlement Statements that it receives. The Scheduling Coordinator, Black Start Generator, or Participating TO shall be deemed to have validated each Preliminary Settlement Statement unless it has raised a dispute or reported an exception within eight (8) Business Days from the date of issuance. Once validated, a Preliminary Settlement Statement shall be binding on the Scheduling Coordinator, Black Start Generator or Participating TO to which it relates, unless the ISO performs a Settlement re-run pursuant to Section 11.6.3 of this ISO Tariff.

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The notice of dispute, if any, shall state clearly the Trading Day, the issue date of the Preliminary Statement, the item disputed, the reasons for the dispute, the amount claimed (if appropriate) and shall be accompanied with all available evidence reasonably required to support the claim.

11.7.3 Validation of Final Settlement Statements.

Each Scheduling Coordinator, Black Start Generator or Participating TO shall have the opportunity to review the Incremental Changes that appear on the Final Settlement Statement that it receives. The Scheduling Coordinator, Black Start Generator or Participating TO shall be deemed to have validated the Incremental Changes on each Final Settlement Statement unless it has raised a dispute or reported an exception regarding those Incremental Changes within ten (10) Business Days from the date of issuance. Once validated, the Incremental Changes on the Final Settlement Statement shall be binding on the Scheduling Coordinator, Black Start Generator or Participating TO to which it relates, unless the ISO performs a Settlement re-run pursuant to Section 11.6.3 of this ISO Tariff.

The notice of dispute shall state clearly the Trading Day, the issue date of the Final Settlement Statement, the item disputed, the reasons for the dispute, the amount claimed (if appropriate) and shall be accompanied with all available evidence reasonably required to support the claim.

11.7.4 Recurring Disputes or Exceptions.

A Scheduling Coordinator, Black Start Generator or Participating TO may request the ISO to treat as recurring a dispute or exception raised in accordance with Sections 11.7.2 and 11.7.3 above, if a dispute or exception would apply to subsequent Preliminary and Final Settlement Statements. A request for recurring treatment may be made for any valid reason provided that subsequent Preliminary and Final Settlement Statements would be affected, including but not limited to, that the disputed calculation will recur, or that a disagreement as to policy will affect calculations in subsequent Preliminary and Final Settlement Statements. If a Scheduling Coordinator, Black Start Generator or Participating TO wishes to request that the ISO treat a dispute as recurring, it shall, in the notice, clearly indicate that it requests such treatment and set forth in detail the reasons that support such treatment. To the extent possible, the Scheduling Coordinator, Black Start Generator or Participating TO shall state the types of charges and dates to which the dispute will apply, and provide estimates of the amounts that will likely be claimed on each date.

The ISO shall make a determination on such a request within five (5) Business Days of receipt. To preserve its right to dispute an item, a Scheduling Coordinator, Black Start Generator or Participating TO must continue to raise a dispute or report an exception until it is notified by the ISO that the ISO agrees to treat the dispute or exception as recurring. If the ISO grants a request to treat a dispute or exception as recurring, the dispute raised or exception reported by the Scheduling Coordinator, Black Start Generator or Participating TO shall be deemed to apply to every subsequent Preliminary and Final Settlement Statement provided to the Scheduling Coordinator, Black Start Generator or Participating TO from the date that the ISO grants the request for recurrent treatment until: a) ninety (90) days have elapsed, unless the ISO indicates a different expiration date on its response to the request, in which case the expiration date stated by the ISO, in its response or b) the dispute or exception is resolved, whichever is shorter. The ISO may deny a request that the ISO treat a dispute as recurring for any valid reason, including because the request is not adequately specific as to the basis for recurring treatment or the subsequent calculations that will be affected.

11.7.5 Amendment.

Regarding a dispute related to a Preliminary Settlement Statement, if the ISO agrees with the amount claimed, it shall incorporate the relevant data into the Final Settlement Statement. Regarding a dispute related to an Incremental Change in a Final Settlement Statement, the ISO shall make a determination on the dispute no later than twenty-five (25) Business Days from the issuance of the Final Settlement Statement, and, if the ISO agrees with the amount claimed, shall incorporate the relevant data into the next available Preliminary Settlement Statement.

11.7.6 ISO Contact.

If the ISO does not agree with the amount claimed or if it requires additional information, it shall make reasonable efforts (taking into account the time it received the notice of dispute and the complexity of the issue involved) to contact the relevant Scheduling Coordinator, Black Start Generator or Participating TO to resolve the issue before issuing the Final Settlement Statement. If it is not possible to contact the

relevant party, the ISO shall issue the Final Settlement Statement without taking into account the dispute notice.

11.7.7 Payment Pending Dispute.

Each Scheduling Coordinator, Black Start Generator or Participating TO which receives an invoice shall pay any net debit and shall be entitled to receive any net credit shown in the invoice on the Payment Date, whether or not there is any dispute regarding the amount of the debit or credit. The provisions of Section 13 (Dispute Resolution) of the ISO Tariff shall apply to the disputed amount.

11.8 Payment Procedures.

11.8.1 All Payments to Be Made Through the ISO.

All Scheduling Coordinators shall discharge their obligations to pay the amounts owed by them and shall receive payments of all amounts owed to them under this ISO Tariff only through the ISO.

11.8.2 Accounts to be Established.

The ISO is authorized to establish and maintain bank accounts held in trust for Market Participants and obtain lines of credit and other banking facilities (not exceeding an aggregate amount set by the ISO Governing Board) necessary for the operation of its Settlement and billing procedures. Unless otherwise specified in this Tariff the ISO will recover all costs incurred in connection with these ISO banking facilities through the appropriate component of the Grid Management Charge. The ISO shall establish and operate the following accounts:

11.8.2.1 An ISO Clearing Account to and from which all payments are made;

11.8.2.2 An ISO Reserve Account from which any debit balances on the ISO Clearing Account at the close of banking business on each Business Day shall be settled or reduced in accordance with this ISO Tariff. The ISO shall use the security provided by a Scheduling Coordinator pursuant to Section 12.1 of this ISO Tariff, if necessary, to clear any debit balances on the ISO Reserve Account that may arise as a result of that Scheduling Coordinator's failure to pay an amount due under this ISO Tariff.

11.8.2.2.a An ISO Surplus Account.

11.8.2.3 Such other accounts as the ISO deems necessary or convenient for the purpose of efficiently implementing the funds transfer system under this ISO Tariff. The ISO shall notify Market Participants of the establishment of such accounts through the ISO Home Page.

11.8.2.4 Accounts of the Scheduling Coordinators and Participating TOs.

Each Scheduling Coordinator and each Participating TO shall establish and maintain a Settlement Account at a commercial bank located in the United States and reasonably acceptable to the ISO which can effect money transfers via Fed-Wire where payments to and from the ISO Clearing Account shall be made in accordance with this ISO Tariff. Scheduling Coordinators may, but will not be required to, maintain separate accounts for receipts and payments. Each Scheduling Coordinator shall notify the ISO of its account details and of any changes to those details in accordance with the provisions of its Scheduling Coordinator Agreement. Participating TOs will notify the ISO of their Settlement Account details in accordance with Section 2.2.1 of their Transmission Control Agreement and may notify the ISO from time to time of any changes by giving at least 7 days written notice before the new account becomes operational.

11.8.3 Declaration of Trust.

All ISO Accounts established pursuant to Section 11.8.2 of this ISO Tariff shall be opened and operated by the ISO on trust for Market Participants, in accordance with this ISO Tariff. Each such account shall be maintained at a bank or other financial institution in California and shall bear a name indicating that it is a trust account.

11.8.4 No Co-Mingling.

The ISO shall not co-mingle any funds standing to the credit of an ISO Account with its other funds and shall promptly withdraw any amounts paid into an ISO Account representing amounts paid for the account of the ISO.

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

Settlement Statements of those ISO Creditors. Such charge shall be credited to the Reserve Account.

11.8.5.3 Surplus Account.

The ISO shall establish and maintain a bank account in accordance with this Protocol denominated the "ISO Surplus Account". The ISO Surplus Account shall include:

- (a) Any amounts paid to the ISO in respect of penalties or sanctions referred to in Section 11.2.9 shall be credited to the Surplus Account, subject, however, to Section 11.8.5.3 (b).
- (b) The funds referred to in Section 11.8.5.3 (a) pertaining to penalties or sanctions as provided in Section 11.2.9 shall first be applied towards any expenses, loss or costs incurred by the ISO except for that portion of those amounts collected pursuant to EP 9.4. Any excess after such application will be credited to the Surplus Account pursuant to Section 11.8.5.3 (a).
- (c) The funds referred to in Section 11.8.5.3 (a) pertaining to default interest referred to in Section 11.12.1 shall first be applied towards any unpaid creditor balances for the trade month in which the default interest was assessed and second to any other unpaid creditor balances. Only after all unpaid creditor balances are satisfied in full will any excess funds pertaining to default interest be credited to the Surplus Account pursuant to Section 11.8.5.3 (a).

In the event that there are funds in the ISO Surplus Account in excess of an amount to be determined by the ISO Governing Board and noticed by the ISO to Market Participants, the amount of such excess will be distributed to Scheduling Coordinators using the same method of apportioning the refund as the method employed in apportioning the liability for the Grid Management Charge.

11.9 Invoices.

The ISO shall prepare and send to each Scheduling Coordinator, Black Start Generator or Participating TO two invoices for each calendar month. The first invoice will be based on the Preliminary Settlement Statements and the second invoice will be based on the Final Settlement Statement(s). Each invoice will show amounts which are to be paid by or to each Scheduling Coordinator, Black Start Generator or Participating TO, the Payment Date, being the date on which such amounts are to be paid or received and details of the ISO Clearing Account to which any amounts owed by Scheduling Coordinators, Black Start Generator or Participating TO are to be paid.

A separate invoice for the Grid Management Charge, stating the rate, billing determinant volume and total charge for each of its eight components, will be issued by the ISO to the Scheduling Coordinator. A separate invoice for Interest, issued on the preliminary invoice date, stating the total charges for each Trade Month in which interest is charged, will be issued by the ISO. The ISO will issue separate invoices for NERC/WECC Charges as described in Section 11.2.19.

Reruns, post closing adjustments and the financial outcomes of Dispute Resolution may be invoiced separately from monthly market activities. The ISO shall provide a market notice at least 30 days prior to such invoicing identifying the components of such invoice.

11.9A Emergency Procedures.

11.9A.1 Use of Estimated Data.

In the event of an emergency or a failure of any of the ISO software or business systems, the ISO may use estimated Settlement Statements and invoices and may implement any temporary variation of the timing requirements relating to the Settlement and billing process contained in the ISO Tariff. Details of the variation and the method chosen to produce estimated data, Settlement Statements and invoices will be published on the ISO Home Page.

11.9A.2 Payment of Estimated Statements and Invoices.

When estimated Settlement Statements and invoices are issued by the ISO, payments between the ISO and Market Participants shall be made on an estimated basis and the necessary corrections shall be

made by the ISO as soon as practicable. The corrections will be reflected as soon as practicable in later Settlement Statements and invoices issued by the ISO in the manner set forth in Section 11.5 of the ISO Tariff. Failure to make such estimated payments shall result in the same consequences as a failure to make actual payments.

11.9A.3 Validation and Correction of Estimated Statements and Invoices.

The ISO shall use its best efforts to verify the estimated data and to make the necessary corrections as soon as practicable. The corrections will be reflected as soon as practicable in later Settlement Statements and invoices issued by the ISO.

11.9A.4 Estimated Statements to be Final.

In the event that the ISO is of the opinion that, despite its best efforts, it is not possible for it to verify the estimated data because actual data is not reasonably expected to become available to the ISO in the foreseeable future, the ISO shall consult with the Market Participants in order to develop the most appropriate substitute data including using data provided by Market Participants. Following such determination of substitute data, the ISO shall send to the relevant Market Participants revised Settlement Statements and Invoices. The provisions of Section 11.7.6 shall apply to payment of revised invoices issued in accordance with these emergency procedures. Failure to make payments of such revised invoices shall result in the same consequences as a failure to make actual payments.

11.10 Instructions for Payment.

Each Scheduling Coordinator shall remit to the ISO Clearing Account the amount shown on the invoice as payable by that Scheduling Coordinator for value not later than 10:00 a.m. on the Payment Date.

11.11 ISO's Responsibilities.

On the due date for payment of amounts shown in an invoice, the ISO shall ascertain whether all amounts required to be remitted to the ISO Clearing Account have been credited to it. If any such amount has not been so credited, it shall ascertain which Scheduling Coordinators have failed to pay the amount owed by them and it may take steps to recover any overdue amount.

11.12 Non-payment by a Scheduling Coordinator.

11.12.1 Notification and Interest.

If a Scheduling Coordinator becomes aware that a payment for which it is responsible will not be remitted to the ISO Clearing Account on time, it shall immediately notify the ISO of the fact and the reason for the non-payment. If the Scheduling Coordinator fails to pay any sum to the ISO when due and the ISO is unable to enforce the Security (if any) provided by the defaulting Scheduling Coordinator, the Scheduling Coordinator shall pay interest on the overdue amount for the period from the Payment Date to the date on which the payment is remitted to the ISO Clearing Account, together with any related transaction costs incurred by the ISO. The ISO shall apply all such Interest payments on the Default Amount on a pro rata basis to ISO Creditors in relation to amounts past due in the order of the creation of such debts.

11.12.2 Payment Default.

Subject to Section 11.12.3, if by 10:00 am on a Payment Date the ISO, in its reasonable opinion, believes that all or any part of any amount due to be remitted to the ISO Clearing Account by any Scheduling Coordinator will not or has not been remitted and there are insufficient funds in the relevant Scheduling Coordinator's ISO prepayment account (the amount of insufficiency being referred to as the "Default Amount"), the ISO shall take the following actions to enable the ISO Clearing Account to clear not later than the close of banking business on the relevant Payment Date:

11.12.2.1 Enforcing the Security of a Defaulting Scheduling Coordinator.

Subject to Section 11.12.3, the ISO shall make reasonable endeavors to enforce the defaulting Scheduling Coordinator's Security (if any) to the extent necessary to pay the Default Amount. If it is not practicable to obtain clear funds in time to effect payment to ISO Creditors on the same day the ISO shall proceed in accordance with 11.12.2.2 or 11.16.1 as applicable.

11.12.2.2 Use of ISO Reserve Account.

If there are funds standing to the credit of the ISO Reserve Account (including the proceeds of drawings under banking facilities described in Section 11.8.5.2) the ISO shall debit the ISO Reserve Account with the Default Amount in order to clear the ISO Clearing Account and effect payment to the ISO Creditors.

11.12.2.3 Action against a Defaulting Scheduling Coordinator.

The ISO shall as soon as possible after taking action under 11.12.2.2 take any steps it deems appropriate against the defaulting Scheduling Coordinator to recover the Default Amount (and any Interest as set out in Section 11.12.1) including enforcing any Security, exercising its rights of recoupment or set-off and/or bringing proceedings against the defaulting Scheduling Coordinator pursuant to Section 11.20.1 of the ISO Tariff.

11.12.3 Default to be Remedied Promptly.

In the event that the ISO reasonably believes that an outstanding amount which has not been paid by 10:00 am on the relevant Payment Date, is likely to be paid no later than close of banking business on the next Business Day then the ISO may, but shall not be obliged to, delay enforcing that ISO Debtor's Security or taking other measures to recover payment until after the close of banking business on the next Banking Day but Interest shall nonetheless accrue pursuant to Section 11.12.1.

11.12.4 Set-Off.

The ISO is authorized to recoup, set off and apply any amount to which any defaulting ISO Debtor is or will be entitled, in or towards the satisfaction of any of that ISO Debtor's debts arising under the ISO Settlement and billing process. Each ISO Creditor and each ISO Debtor expressly acknowledges the following application of funds: first to the current month's Grid Management Charge, and then as described in 11.12.5 unless otherwise specified in accordance with Section 11.16.

11.12.5 Order of Payments.

Unless otherwise specified in accordance with Section 11.16, the ISO shall apply payments received in respect of amounts owing to ISO Creditors to repay the relevant debts in the order of the creation of such debts.

11.12.6 Interest Accruing while Enforcing the Security.

If the ISO has debited the Reserve Account and it subsequently succeeds in enforcing the Security provided by the defaulting Scheduling Coordinator, the ISO shall be entitled to withdraw from such Security in addition to the Default Amount, all costs incurred and interest accrued to the ISO as a result of debiting the Reserve Account from the date of such debit to the date of enforcement of the said Security.

11.12.7 Application of Funds Received.

Amounts credited to the ISO Clearing Account in payment of a Default Amount (as set out in Section 11.8.5.2.1) or as a result of enforcing the defaulting ISO Debtor's Security shall be applied to the ISO Reserve Account pursuant to Section 11.8.5.2.1 to reduce amounts outstanding under any ISO banking facilities used to fund the ISO Reserve Account on the relevant Payment Date and the balance (if any) shall be applied to reimburse pro rata any ISO Creditors whose payments were reduced pursuant to Section 11.16.1.

11.13 [Not Used]

11.14 [Not Used]

11.15 Prohibition on Transfers.

The ISO shall at no time instruct the ISO Bank to transfer any sum from an ISO Account to another account (not being an ISO Account) unless that account is a Settlement Account or the amount is owed to the ISO under this ISO Tariff.

11.16 Alternative Payment Procedures.

11.16.1 Pro Rata Reduction to Payments.

If it is not possible to clear the ISO Clearing Account on a Payment Date because of an insufficiency of funds available in the ISO Reserve Account or by enforcing any guarantee, letter of credit or other credit support provided by a defaulting Scheduling Coordinator, the ISO shall reduce payments to all ISO Creditors proportionately to the net amounts payable to them on the relevant Payment Date to the extent necessary to clear the ISO Clearing Account. The ISO shall account for such reduction in the ISO ledger

accounts as amounts due and owing by the non-paying ISO Debtor to each ISO Creditor whose payment was so reduced. The provisions of this section shall not apply to non-payment of any penalty amount that a Scheduling Coordinator has disputed and FERC has specifically authorized the Scheduling Coordinator to net its payment to the ISO by the amount of the penalty in question in accordance with Section 37.9.3, in which case the non-payment amount will be allocated exclusively to the ISO penalty trust account and not allocated to ISO Creditors.

11.16.2 Payment of Defaulted Receivables.

Collections of defaulted receivables (other than Interest) will be distributed pro rata to ISO Creditors for the month of default.

(1) If the total collected in that closing related to the past due trade month is less than \$5,000, then the funds shall accumulate in an Interest-bearing account until either: (a) the account exceeds \$5,000, (b) there have been no distributions from the account for six months, or (c) all defaults for that month have been collected exclusive of any bankruptcy defaults.

(2) If all ISO Creditors for that trade month have been paid, then the proceeds will be paid pro rata to the ISO Creditors in the oldest unpaid trade month.

(3) This provision is also applicable to the amounts netted against ISO Creditor balances related to prior defaulted receivables.

(4) All defaulted receivables disbursed under this Section shall be disbursed in accordance with the timeframes set forth in Section 11.8.5.1.

11.17 [DELETED]

11.18 Payment Errors.

11.18.1 Overpayments.

If for any reason, including the negligence of the ISO Bank or the ISO, an ISO Creditor receives an overpayment on any Payment Date, the ISO Creditor shall within two (2) Business Days from the date of

receipt of the funds into its Scheduling Coordinator Settlement Account, notify the ISO of the amount of the overpayment and shall forthwith pay the overpayment into an ISO Account specified by the ISO.

11.18.2 Repayment of Overpayment.

If prior to an ISO Creditor notifying the ISO of the overpayment, the ISO receives notice (from the ISO Bank or otherwise) of the overpayment, the ISO shall within two (2) Business Days notify the recipient of the overpayment. The ISO shall be responsible for payment to those entitled to the sum which has been overpaid.

11.18.2.a Overpayment Held In Trust.

Until an ISO Creditor refunds the overpayment to the ISO, the ISO Creditor shall be deemed to hold the amount of such overpayment on trust for any ISO Creditor which may have been underpaid in consequence of such overpayment, pro rata to the amount of the underpayment.

11.18.2.b Interest on Overpayment.

- (a) If an overpayment is repaid by an ISO Creditor in accordance with Section 11.18.1 of the ISO Tariff, the ISO shall be entitled to Interest on the amount of the overpayment at the prime rate of the bank where the Settlement Account of the overpaid ISO Creditor is located from the date the overpayment was received to the time that the repayment is credited to the relevant ISO Account.
- (b) If the overpayment (or any part of it) is not repaid by an ISO Creditor in accordance with Section 11.18.1 of the ISO Tariff, the ISO shall be entitled to Interest on the amount of the overpayment from the expiry of the two day period referred to in that Section until the repayment is credited to the relevant ISO Account and the ISO will be entitled to treat the overpayment (and any Interest accruing thereon) as a Default Amount to which Section 11.12.2 will apply.

11.18.2.c Treatment of Amounts Outstanding as a Result of an Overpayment.

The ISO shall apply the amount of any overpayment repaid (including interest received) to credit any underpaid ISO Creditors pro rata to the amounts of their underpayments on the same day of receipt, or if not practicable, on the following Business Day.

11.18.3 Underpayments.

If for any reason, including the negligence of the ISO Bank or the ISO, an ISO Creditor receives on the relevant Payment Date an underpayment, the ISO Creditor shall within two (2) Business Days from receipt into its Settlement Account, notify the ISO of the amount of the underpayment, and the ISO after consultation with the ISO Bank, shall use all reasonable endeavors to identify such entity as shall have received any corresponding overpayment and promptly correct the underpayment. If, by reason of negligence, the ISO holds or has under its control after five (5) Business Days from receipt in the ISO Clearing Account amounts which it ought properly to have paid to ISO Creditors, such ISO Creditors shall be entitled to interest on such amounts, for such period as the ISO improperly holds or has such amounts under its control.

11.19 Defaults.

Each ISO Creditor shall give notice to the ISO before instituting any action or proceedings in any court against an ISO Debtor to enforce payments due to it.

11.20 Proceedings to Recover Overdue Amounts.

11.20.1 Proceedings Brought by the ISO.

Without prejudice to the right of any Scheduling Coordinator to bring such proceedings as it sees fit in connection with matters related to the recovery of amounts owed to it, the ISO may bring proceedings against any Scheduling Coordinator on behalf of those Scheduling Coordinators who have indicated to the ISO their willingness for the ISO first so to act, for the recovery of any amounts due by that Scheduling Coordinator, if the ISO has first reached agreement with the Scheduling Coordinators as to the appropriate remuneration, is indemnified to its reasonable satisfaction and receives such security as it

may reasonably request against all costs, claims, expenses (including legal fees) and liabilities which it will or may sustain or incur in complying with such instructions.

11.20.2 Evidence of Unpaid Amount.

The ISO shall, on request, certify in writing the amounts owed by an ISO Debtor that remain unpaid and the ISO Creditors to whom such amounts are owed and shall provide certified copies of the relevant Preliminary and Final Settlement Statements, invoices and other documentation on which the ISO's certificate was based to the ISO Debtor and the relevant ISO Creditors. An ISO certificate given under this Section 11.20.2 may be used as prima facie evidence of the amount due by an ISO Debtor to ISO Creditors in any legal proceedings.

11.21 Data Gathering and Storage.

11.21.1 Required Capabilities.

The ISO shall ensure that the Settlement process shall contain, at a minimum, the following data gathering and storage capabilities:

- (a) the accurate, time-sequenced, end-to-end traceability of the Settlements process so that Scheduling Coordinators and Participating TOs can fully verify their Settlement Statements;
- (b) the ability to specify and accept data that is specifically needed for audit trail requirements; and
- (c) the archiving of Meter Data, Settlement runs and other information used to prepare Settlement Statements to be consistent with the time frame required to re-run the Settlement process by state laws and the rules of the Local Regulatory Authority.

11.21.2 Data Dissemination.

Data shall not be disseminated by the ISO except as permitted in this ISO Tariff.

11.23 Communications.

Preliminary Settlement Statements, Final Settlement Statements and invoices will be considered issued to ISO Creditors or ISO Debtors when released by the ISO via direct computer link. Communications on a Payment Date relating to payment shall be made by the fastest practical means including by telephone. If there is a failure of a communication system and it is not possible to communicate by electronic means, then the ISO or ISO Creditor or ISO Debtor, as the case may be, shall communicate by facsimile but only if the recipient is first advised by telephone to expect the facsimile. Methods of communication between the ISO and Market Participants may be varied by the ISO giving not less than 10 days notice to Market Participants on the WEnet.

11.24 ISO Payments Calendar.

11.24.1 Preparation.

In September of each year, the ISO will prepare a draft ISO Payments Calendar for the following calendar year showing for each Trading Day:

- (a) The date by which Scheduling Coordinators are required to provide Settlement Quality Meter Data for all their Scheduling Coordinator Metered Entities for each Settlement Period in the Trading Day;
- (b) The date on which the ISO will issue Preliminary Settlement Statements and invoices to Scheduling Coordinators, Black Start Generators and Participating TOs for that Trading Day;
- (c) The date by which Scheduling Coordinators, Black Start Generators and Participating TOs are required to notify the ISO of any disputes in relation to their Preliminary Settlement Statements pursuant to Section 11.7.2;
- (d) The date on which the ISO will issue Final Settlement Statements and invoices to Scheduling Coordinators, Black Start Generators and Participating TOs for that Trading Day;

- (e) The date and time by which ISO Debtors are required to have made payments into the ISO Clearing Account in payment of invoices for that Trading Day; and
- (f) The dates and times on which ISO Creditors will receive payments from the ISO Clearing Account of amounts owing to them for that Trading Day.
- (g) In relation to Reliability Must-Run Charges and Payments, the details set out in paragraph 3 of Appendix N, Part J.

The ISO will make a draft of the ISO Payments Calendar available on the ISO Home Page to Scheduling Coordinators, Black Start Generators, Participating TOs and Owners any of which may submit comments and objections to the ISO within two weeks of the date of posting of the draft on the ISO Home Page. No later than October 31st in each year, the ISO will publish the final ISO Payments Calendar for the following calendar year, after considering the comments and objections received from Scheduling Coordinators, Black Start Generators, Participating TOs and Owners. The final ISO Payments Calendar will be posted on the ISO Home Page, and will show for the period from 1 January to 31 December in the next succeeding year (both dates inclusive), the dates on which Settlement Statements shall be published by the ISO and the Payment Dates on which the ISO will pay the Participating TO the Wheeling revenues allocated to them pursuant to Section 26.1.4.3 of this ISO Tariff.

11.24.2 Distribution.

Any ISO Payments Calendar prepared pursuant to this Section 11.24 shall be distributed promptly to each Scheduling Coordinator, each Participating TO, the ISO Bank, the ISO Audit Committee and the ISO Governing Board and shall be published on the ISO Home Page.

11.24.3 Final Calendar Binding.

The final ISO Payments Calendar shall be binding on the ISO and on Scheduling Coordinators, Black Start Generators, Participating TOs and Owners.

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.

11.25 [NOT USED]

11.26 [NOT USED]

11.27 [NOT USED]

11.28 [NOT USED]

11.29 [NOT USED]

11.30 [NOT USED]

11.31 Decline Charge for Hourly Pre-Dispatch Supplemental Energy.

The Decline Potential Charge – Imports shall apply to any portion of an Hourly Pre-Dispatch Supplemental Energy bid for an import that is not delivered for any reason (with no exceptions based on the circumstances of a particular failure to deliver). The Decline Potential Charge – Exports shall apply to any portion of an Hourly Pre-Dispatch bid for an export that is not delivered for any reason (with no exceptions based on the circumstances of a particular failure to deliver). For any Settlement Interval, the Decline Potential Charge – Imports or Decline Potential Charge – Exports, as the case may be, shall equal the MWh quantity of the import or export not delivered multiplied by the greater of \$10/MWh or fifty percent (50%) of the bid price. The Decline Potential Charge – Imports and Decline Potential Charge - Exports will be calculated for each Hourly Pre-Dispatch bid that is not delivered, provided that only the Decline Monthly Charge – Imports and Decline Monthly Charge - Exports shall be payable by the Scheduling Coordinator as described in Section 11.31.1.

11.31.1 Decline Monthly Charge – Imports.

The Decline Monthly Charge – Imports shall be applied to each Scheduling Coordinator on the Settlement Statements issued for the last Trading Day of each trading month, and shall be the sum of the Scheduling Coordinator's Decline Potential Charges – Imports for each Settlement Interval during that trading month multiplied by a ratio. The ratio will represent the portion of the Scheduling Coordinator's declined Hourly Pre-Dispatch Supplemental Energy bids for imports that exceed the applicable exemption threshold during the trading month.

- (a) The ratio will be calculated as follows:
 - (i) the Scheduling Coordinator's total MWh quantity of Hourly Pre-Dispatch Supplemental Energy bids for imports that were not delivered during that Trading Month minus the applicable exemption threshold, divided by
 - (ii) the Scheduling Coordinator's total MWh quantity of Hourly Pre-Dispatch Supplemental Energy bids for imports that were not delivered during the trading month.

- (b) The applicable exemption threshold is the greater of the following:
 - (i) the Decline Threshold Quantity – Imports/Exports; or
 - (ii) the total MWh quantity of Hourly Pre-Dispatch Supplemental Energy bids for imports during the trading month multiplied by the Scheduling Coordinator's Decline Threshold Percentage – Imports/Exports.

Notwithstanding the foregoing, the Decline Monthly Charge – Imports shall equal zero if either:

- (a) The percentage of the MWh quantity of Hourly Pre-Dispatch Supplemental Energy bids for imports that the Scheduling Coordinator did not deliver during the trading month is less than the Decline Threshold Percentage – Imports/Exports;
or
- (b) The total MWh quantity of Hourly Pre-Dispatch Supplemental Energy bids for imports that the Scheduling Coordinator did not deliver in the applicable trading month is less than the Decline Threshold Quantity – Imports/Exports.

11.31.2 Decline Monthly Charge – Exports.

The Decline Monthly Charge – Exports shall be applied to each Scheduling Coordinator on the Settlement Statements issued for the last Trading Day of each trading month, and shall be the sum of the Scheduling Coordinator's Decline Potential Charges – Exports for each Settlement Interval during that trading month multiplied by a ratio. The ratio will represent the portion of the Scheduling Coordinator's declined Hourly Pre-Dispatch Supplemental Energy bids for exports that exceed the applicable exemption threshold during the trading month.

- (a) The ratio will be calculated as follows:
 - (i) the Scheduling Coordinator's total MWh quantity of Hourly Pre-Dispatch Supplemental Energy bids for exports that were not delivered during that trading month minus the applicable exemption threshold, divided by
 - (ii) the Scheduling Coordinator's total MWh quantity of Hourly Pre-Dispatch Supplemental Energy bids for exports that were not delivered during the trading month.

- (b) The applicable exemption threshold is the greater of the following:
 - (i) the Decline Threshold Quantity – Imports/Exports; or
 - (ii) the total MWh quantity of Hourly Pre-Dispatch Supplemental Energy bids for exports during the trading month multiplied by the Scheduling Coordinator's Decline Threshold Percentage – Imports/Exports.

Notwithstanding the foregoing, the Decline Monthly Charge – Exports shall equal zero if either:

- (a) The percentage of the MWh quantity of Hourly Pre-Dispatch Supplemental Energy bids for exports that the Scheduling Coordinator did not deliver during the trading month is less than the Decline Threshold Percentage – Imports/Exports;
or
- (b) The total MWh quantity of Hourly Pre-Dispatch Supplemental Energy bids for exports that the Scheduling Coordinator did not deliver in the applicable trading month is less than the Decline Threshold Quantity – Imports/Exports.

11.31.3 Allocation of Import/Export Decline Monthly Charges Collected.

On the Settlement Statements issued for the last Trading Day of the applicable trading month, each Scheduling Coordinator shall receive a credit for its share of the total of all Decline Monthly Charges – Imports and Decline Monthly Charges – Exports assessed to Scheduling Coordinators for the applicable trading month. The credits shall be allocated according to the proportion of each Scheduling Coordinator's Demand (including exports) to total Demand (including exports) in (or from) the ISO Control Area during the trading month.

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 or CRRs and to CRR Holders for the holding of CRRs. Each Market Participant (including each Scheduling Coordinator, UDC, MSS, CRR Holder, or Candidate CRR Holder) or FTR Bidder shall secure its financial transactions with the ISO (including its participation in any auction of FTRs or CRRs and for the holding of CRRs) 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 Sections 12.1.1A, 12.1.1A.1, 12.1.1A.2.

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.

12.1.1A Unsecured Credit Limit Calculation.

An Unsecured Credit Limit (UCL) for each Market Participant and FTR Bidder that is a Public/Private Corporation, a Governmental Entity, or a Local Publicly Owned Electric Utility and that requests an Unsecured Credit Limit is calculated as follows:

- 1. Rated Public/Private Corporations** – The Unsecured Credit Limit 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 Unsecured Credit Limit is the lesser of \$250 million or an amount equal to the Market Participant's or FTR Bidder's 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 Unsecured Credit Limit 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. (a) Unrated Governmental Entities Other Than Those that Receive Appropriations

from the Federal Government or a State Government – The Unsecured Credit Limit is 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.

(b) Unrated Governmental Entities that Receive Appropriations from the Federal

Government or a State Government – The Unsecured Credit Limit is the lesser of \$250 million dollars 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.

5. Local Publicly Owned Electric Utilities – 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 \$1 million dollars 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.A(3) or 12.1.1A(4) in order to establish an Unsecured Credit Limit as the greater of \$1 million dollars or the amount determined as provided in this Section 12.1.1A(5). A public entity that is not a Local Publicly Owned Electric Utility is not entitled to an Unsecured Credit Limit of \$1 million dollars under this Section 12.1.1A(5) but may seek to

establish an Unsecured Credit Limit as provided in 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 \$1 million dollars 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 \$1 million dollars 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 \$1 million dollars, 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 pursuant to this Section 12.1.1A shall be subject to the ISO's consideration of the same qualitative factors that apply to all Market Participants and FTR Bidders as set forth in Section 12.1.1.1 and, accordingly, the ISO may adjust their Unsecured Credit Limits pursuant to Section 12.1.1. The \$250 million hard cap on Unsecured Credit Limits specified in Section 12.1.1 has been set with respect to the length of the current ISO Payments Calendar, *i.e.*, a maximum of 95 Trading Days of charges outstanding. Upon implementation of payment acceleration (scheduled for 2008), the ISO expects 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 Tangible Net Worth and Net Assets.

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 Tangible Net Worth Percentage (TNWP) or Net Assets Percentage (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.

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 median default probability calculated by Moody's KMV (*i.e.*, MKMV) for Standard & Poor's and Moody's long-term credit rating classes is provided on the ISO Website at <http://www.caiso.com/1bd8/1bd8b09916e50.html>. Default probabilities are available from each NRSRO.
- c. 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. $CDP \text{ for Rated Public/Private Corporations} = (ARDP * 50\%) + (MKDP * 50\%)$
- b. $CDP \text{ for Unrated Public/Private Corporations} = MKDP * 100\%$
- c. $CDP \text{ for Rated Governmentally Owned Utilities} = ARDP * 100\%$

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. $TNW \text{ for Rated/Unrated Public/Private Corporations} = \text{Assets minus Intangibles (e.g., Good Will) minus Liabilities}$
- b. $NA \text{ for Rated Governmental Entities} = \text{Total Assets minus Total Liabilities}$

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 Section 12.1.1.1.

- a. $\text{Final UCL} = \text{UCL from Step 7} * (0 - 100\%)$

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;
- j) The state or local regulatory environment; *and*
- k) *Affiliate disclosure information provided pursuant to Section 39.9 of Part M of Appendix BB.*

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 12.1.1A. A Market Participant or FTR Bidder, upon request, will be provided a written analysis as to how the provisions in Section 12.1.1A 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.

12.1.5A Calculation of Estimated Aggregate Liability.

12.1.5A.1 Calculation Methodology Based on the Level Posting Period.

Except as described in Section 12.1.5A.2, the ISO shall use the method described in this Section 12.1.5A.1 to calculate each Market Participant's Estimated Aggregate Liability. The Estimated Aggregate Liability is based on a "Level Posting Period" equal to 102 Trading Days, which represents the maximum number of Trading Days outstanding at a given time based on the ISO's Payments Calendar (95 Trading Days) plus seven Trading Days based on the allowable period for Market Participants to respond to ISO requests for additional collateral (five Business Days). The charges the ISO shall use to calculate Estimated Aggregate Liability shall be charges described or referenced in the ISO Tariff. The ISO shall calculate the Estimated Aggregate Liability for each Market Participant for a given Level Posting Period by aggregating the following obligations:

- Outstanding obligations – Any past-due open balances of amounts payable by and amounts receivable from the Market Participant, including unpaid FERC Annual Charge balances and excluding balances covered by bankruptcies.

- Invoice obligations – Obligations from either a preliminary or a final invoice that has been issue but not yet paid.
- Actual Settlement obligations – The Market Participant’s preliminary and final Settlement obligations up to the date of the latest Preliminary Settlement Statement.
- Estimated obligations – Estimated charges for the Market Participant for the balance of the Level Posting Period. The ISO shall calculate estimated obligations for the Market Participant by multiplying (i) a daily average of published, actual Settlement charges for the Market Participant by (ii) the number of days remaining in the Level Posting Period for which actual Settlement data is unavailable. In calculating (i), above, the ISO shall separate the Market Participant’s Settlement activity into daily market activity, monthly market activity, and Grid Management Charge activity, and shall determine the daily average of charges for each such type of activity separately based on the different frequencies with which charges for these types of activities are assessed. The daily average charges used in (i), above, shall normally be based on two months of available historical Settlement data for the Market Participant. The ISO may review the trend of Market Participant historical charges and determine that an alternative of one month or twelve months of historical charges would result in a more accurate estimate, and may use such data to calculate the daily average charges.

For a Market Participant that maintains multiple BAID numbers, the Estimated Aggregate Liability of the Market Participant as a legal entity shall 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. Market Participants may recommend changes to the liability estimates produced by the ISO’s Estimated Aggregate Liability calculation through the dispute procedures described in Section 12.4.2.

12.1.5A.2 Calculation Methodology Applicable to New Market Participants.

Each new Market Participant (and each Market Participant that has previously been inactive) is required to post an initial Financial Security Amount to cover a minimum of 14 Trading Days of estimated obligations as well as additional Financial Security as obligations are incurred. This initial posting

requirement is based on anticipated scheduling/trading practices and overall volumes, and shall be considered to be equal to the Market Participant's Estimated Aggregate Liability. Until the amount of time elapsed from such Market Participant's initial participation in the ISO Market equals the maximum length of the ISO payment cycle (*i.e.*, 95 Trading Days), the ISO shall monitor the Market Participant's ongoing security requirement by comparing its actual obligations against its estimated obligations to determine if the Market Participant must provide any additional Financial Security Amount in order to ensure that its Estimated Aggregate Liability does not exceed its Aggregate Credit Limit. Once the amount of time elapsed from the Market Participant's initial participation in the ISO Market equals 95 Trading Days, the ISO shall begin calculating the Market Participant's Estimated Aggregate Liability pursuant to Section 12.1.5A.1.

12.1.5A.3 Special Circumstances.

12.1.5A.3.1 Daily Adjustments and Disputes.

Charges associated with daily adjustments and disputes that are regularly calculated by the ISO Settlement system will be included in the ISO's determinations of Estimated Aggregate Liability as the charges are calculated.

12.1.5A.3.2 FERC Refund Orders.

The ISO will assess its ability to reasonably calculate the charges associated with a refund before the ISO's Settlement system is re-run. If the ISO can reasonably apportion the refund charges to specific Market Participants, it will include the amounts in its calculation of Estimated Aggregate Liability for those Market Participants and will request Financial Security from them accordingly. If the ISO determines that complexities of a FERC refund order preclude the ISO from reasonably being able to include refunds in its calculation of Estimated Aggregate Liability, the ISO will not request Financial Security associated with the required refunds until the refunds are processed through the ISO Settlement system. However, if feasible, the ISO will make available to Market Participants, for informational purposes only, an aggregate forecast of the effect that providing the refunds will have on the ISO's calculation of Estimated Aggregate Liability.

12.1.5A.3.3 ISO ADR Procedures.

The ISO will handle transactions associated with the ISO ADR Procedures in the same manner as transactions associated with refunds provided pursuant to Section 12.1.5A.3.2.

12.1.5A.4 FTR Auction Financial Security Requirements.

The credit requirements related to participation in the ISO's annual Firm Transmission Rights (FTR) auction shall be 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 Aggregate Credit Limit 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 Unsecured Credit Limit 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.

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 or 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.

12.4.1 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.

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, including limiting eligibility to participate in a CRR Allocation or CRR Auction. In such case, the ISO shall notify the Market Participant of its action and the Market Participant shall not be entitled to participate in the ISO's markets or CRR Auctions or submit further Schedules or otherwise participate in the ISO's markets 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 the Market Participant's CRR Entity Agreement or Service Agreement.
- (e) The ISO may resell the CRR Holder's CRRs in whole or in part, including any Long Term CRRs, in a subsequent CRR Auction or bilateral transaction, as appropriate.
- (f) The ISO will not implement the transfer of a CRR if the transferee or transferor has an Estimated Aggregate Liability in excess of their Aggregate Credit Limit.

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.

12.6 Credit Obligations Applicable to CRRs.

12.6.1 Credit Requirements for CRR Allocations.

Subject to applicable requirements of Section 36.9.2 *of Appendix BB* concerning the prepayment of Wheeling Access Charges, Load-Serving Entities eligible to participate in any CRR Allocation are not required to provide additional Financial Security in advance of a CRR Allocation.

12.6.2 Credit Requirements for CRR Auctions.

To establish available credit for participating in any CRR Auction, each *CRR Holder or* Candidate CRR Holder must have an Unsecured Credit Limit or have provided Financial Security in a form consistent with Section 12.1.2. *Each CRR Holder or Candidate CRR Holder may choose to designate a portion of its Unsecured Credit Limit and/or posted Financial Security specifically for the CRR Auction by notifying the ISO of the CRR Holder's or Candidate CRR Holder's intent. Alternatively, the CRR Holder or Candidate CRR Holder may choose to post additional Financial Security to cover its participation in the CRR Auction, and shall notify the ISO of the portion of its total Financial Security to be assigned as its CRR Auction bidding limit.* Each *CRR Holder or* Candidate CRR Holder that participates in a CRR Auction shall ensure that its Aggregate Credit Limit in excess of its Estimated Aggregate Liability is the greater of \$500,000 or *the sum equal to* the sum of the absolute values of all of its bids for CRRs submitted in the relevant CRR Auction *plus the sum of the Credit Margins for all of the CRRs for which the Candidate CRR Holder submits bids in the relevant CRR Auction.* A *CRR Holder or* Candidate CRR Holder that fails to satisfy this requirement shall not be permitted to participate in the relevant CRR Auction, *or shall have bids exceeding its Available Credit Limit for participation in the CRR Auction, in accordance with the above formula, rejected by the ISO on a last-in, first-out basis.*

12.6.3 Credit Requirements for the Holding of CRRs.

12.6.3.1 Credit Requirements Generally.

- (a) Each CRR Holder, whether it obtains CRRs through a CRR Allocation or a CRR Auction, must maintain an Aggregate Credit Limit in excess of its Estimated Aggregate Liability including the credit requirement of the CRR portfolio determined as described in this Section 12.6.3. CRR Holders obtaining CRRs in the initial CRR Allocation will be required to comply with the credit requirements associated with such CRRs as determined by the ISO after completion of the initial CRR Auction. The ISO shall issue a market notice after completion of the initial CRR Auction to announce that CRR Holders obtaining CRRs in the initial CRR Allocation must comply with such credit requirements.

- (b) Each CRR Holder shall be required to ensure that its Aggregate Credit Limit is sufficient to satisfy the credit requirements described in this Section 12.6.3. *Except as provided in this paragraph,* CRRs are evaluated on a portfolio basis as follows. If a CRR Holder owns more than one CRR, such CRR Holder shall be subject to an overall credit requirement that is equal to the sum of the individual credit requirements applicable to each of the CRRs held by such CRR Holder, *which is calculated after the MW associated with any Offsetting CRRs are netted out.* If this sum is positive, the amount will be added to the CRR Holder's Estimated Aggregate Liability. However, if the sum is negative, the CRR Holder's Estimated Aggregate Liability shall not be reduced. *If a CRR Holder holds one or more CRRs obtained through a CRR Allocation and also holds one or more CRRs obtained through a CRR Auction, the individual credit requirements applicable to any of the CRRs obtained through a CRR Allocation may not be netted against the individual credit requirements applicable to any of the CRRs obtained through a CRR Auction in determining such CRR Holder's Estimated Aggregate Liability.*
- (c) The ISO shall reevaluate the credit requirements for holding CRRs, and shall adjust the credit requirements accordingly, not less than monthly. The ISO may adjust the credit requirements for holding CRRs with terms of one year or less *as* at the ISO's discretion to account for changes in the monthly auction prices for CRRs *and changes in the Historical Expected Values for CRRs, or more frequently than monthly if necessary if the ISO finds that actual or anticipated market conditions indicate that CRR credit requirements may be inadequate to cover the financial risk of the CRRs.* The ISO may also adjust the credit requirements for holding Long Term CRRs annually *to* reflect the changes in auction prices of one-year CRRs in annual auctions, and to reflect updates to Credit Margins based on actual Locational Marginal Price data derived from market operations.

- (d) In cases where the ownership of a CRR is to be transferred through either the Secondary Registration System or through Load Migration, the ISO shall evaluate and adjust the credit requirements for both the current owner of the CRR and the prospective owner of the CRR as appropriate prior to the transfer. If additional Financial Security is required from either the current or prospective owner, the transfer will not be completed until such Financial Security has been provided to and accepted by the ISO. *CRRs transferred through the Secondary Registration System will be treated like auctioned CRRs for the purpose of calculating the credit requirements for holding the CRRs, regardless of whether the CRRs were originally allocated or purchased at auction or acquired through the Secondary Registration System. CRRs assigned to Load-gaining or Load-losing Load-Serving Entities as a result of Load Migration will be treated like allocated CRRs for the purpose of calculating the credit requirements for holding the CRRs.*

12.6.3.2 Calculation of the Credit Amount Required to Hold a CRR With a Term of One Year or Less.

Each CRR Holder that holds a CRR with a term of one year or less shall be subject to a credit requirement (\$/MW) equal to the negative of the most recent CRR Auction Price of such CRR *or the Historical Expected Value of such CRR, whichever is lower,* plus the Credit Margin for such CRR. *The CRR Auction Price will be used until twelve (12) months of historical market operations data are available.*

12.6.3.3 Calculation of the Credit Amount Required to Hold a Long Term CRR.

Each CRR Holder that holds a Long Term CRR shall be subject to a credit requirement (\$/MW) equal to (i) the negative of the most recent CRR Auction Price of a CRR with the same source and sink as the Long Term CRR but with only a one-year term, plus (ii) the Credit Margin calculated for the one-year CRR. If there is less than one year remaining in the term of a Long Term CRR, the credit requirement shall be determined pursuant to Section 12.6.3.2.

12.6.3.4 Calculation of Credit Margin.

The Credit Margin (\$/MW) for a CRR is equal to (i) the Expected Congestion Revenue minus (ii) the Fifth Percentile Congestion Revenue of such CRR. Both values will be based on the probability distribution of Congestion revenue of such CRR calculated using historical Locational Marginal Price data, when available, and proxy values, including data taken from Locational Marginal Price studies conducted by the ISO, until such time as historical Locational Marginal Price data is available, with the details of such calculation published in a Business Practice Manual. The ISO may reassess its determinations regarding the Credit Margin determination at any time and shall require additional Financial Security if the reassessment results in an increase in a CRR Holder's Estimated Aggregate Liability that is not covered by a CRR Holder's Aggregate Credit Limit (consisting of the CRR Holder's Unsecured Credit Limit and/or Financial Security).

12.6.4 Credit Requirements for Sales of Allocated CRRs.

Each Load-Serving Entity that sells a CRR obtained through a CRR Allocation shall, as a prerequisite to the sale of any such CRR, have an Aggregate Credit Limit with a sufficient margin to cover the credit requirement for holding the Offsetting CRR that the Load-Serving Entity would be responsible for assuming in the event of Load Migration from the Load-Serving Entity to another Load-Serving Entity pursuant to Section 36.8.5.3 of Appendix BB. The credit requirement for holding the Offsetting CRR will be included in the Estimated Aggregate Liability of the Load-Serving Entity upon the transfer of the allocated CRR.

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.

13.2 Negotiation and Mediation.

13.2.1 Negotiation.

The ISO and Market Participants (party or parties) shall make good-faith efforts to negotiate and resolve any dispute between them arising under ISO Documents prior to invoking the ISO ADR Procedures outlined herein. Each party shall designate an individual with authority to negotiate the matter in dispute to participate in such negotiations.

13.2.2 Statement of Claim.

In the event a dispute is not resolved through such good-faith negotiations, any one of the parties may submit a statement of claim, in writing, to each other disputing party, the ISO ADR Committee, and the ISO Governing Board, which submission shall commence the ISO ADR Procedures. The statement of claim shall set forth in reasonable detail (i) each claim, (ii) the relief sought, including the proposed award, if applicable, (iii) a summary of the grounds for such relief and the basis for each claim, (iv) the parties to the dispute, and (v) the individuals having knowledge of each claim. The other parties to the dispute shall similarly submit their respective statements of claim within fourteen (14) days of the date of the initial statement of claim or such longer period as the chair of the ISO ADR Committee may permit following an application by the responding party. If any responding party wishes to submit a counterclaim in response to the statement of claim, it shall be included in such party's responsive statement of claim. A summary of the statements of claim shall be published by the ISO in the ISO newsletter or WEnet, and any other method adopted by the ISO ADR Committee. No Market Participant shall be considered as having received notice of a claim decided or relief granted by a decision made under these procedures unless the summary of the statements of claim published by the ISO includes such claim or relief.

13.2.3 Selection of Mediator.

After submission of the statements of claim, the parties may request mediation, if at least 75% of the disputing parties so agree, except that where a dispute involves three parties, at least two of the parties must agree to mediation. If the parties agree to mediate, the chair of the ISO ADR Committee shall distribute to the parties by facsimile or other electronic means a list containing the names of at least

seven prospective mediators with mediation experience, or with technical or business experience in the electric power industry, or both, as he or she shall deem appropriate to the dispute. The parties shall either agree upon a mediator from the list provided or from any alternative source, or alternate in striking names from the list with the last name on the list becoming the mediator. The first party to strike off a name from the list shall be determined by lot. The parties shall have seven days from the date of receipt of the ISO ADR Committee chair's list of prospective mediators to complete the mediator selection process and appoint the mediator, unless the time is extended by mutual agreement. The mediator shall comply with the requirements of Section 13.3.2.

13.2.4 Mediation.

The mediator and representatives of the disputing parties, with authority to settle the dispute, shall within fourteen (14) days after the mediator's date of appointment schedule a date to mediate the dispute.

Matters discussed during the mediation shall be confidential and shall not be referred to in any subsequent proceeding. With the consent of all disputing parties, a resolution may include referring the dispute directly to a technical body (such as a WECC technical advisory panel) for resolution or an advisory opinion, or referring the dispute directly to FERC. The ISO shall publish notice of the referral of the dispute in the ISO newsletter or WEnet, and any other method adopted by the ISO ADR Committee.

13.2.5 Demand for Arbitration.

If the disputing parties have not succeeded in negotiating a resolution of the dispute within thirty (30) days of the initial statement of claim or, if within that period the parties agreed to mediate, within thirty (30) days of the parties first meeting with the mediator, such parties shall be deemed to be at impasse and any such disputing party may then commence the arbitration process, unless the parties by mutual agreement agree to extend the time. A party seeking arbitration shall provide notice of its demand for arbitration to the other disputing parties, the ISO ADR Committee and the ISO Governing Board, which shall publish notice of such demand in the ISO newsletter or electronic bulletin board, and any other method adopted by the ISO ADR Committee.

13.3 Arbitration.

13.3.1 Selection of Arbitrator.

13.3.1.1 Disputes Under \$1,000,000.

Where the total amount of claims and counterclaims in controversy is less than \$1,000,000 (exclusive of costs and interest), the disputing parties shall select an arbitrator from a list containing the names of at least 10 qualified individuals supplied by the ISO ADR Committee, or if the ISO is a party to the dispute, the names of at least ten (10) qualified individuals supplied by the American Arbitration Association within 14 days following submission of the demand for arbitration. If the parties cannot agree upon an arbitrator within the stated time, they shall take turns striking names from the list of proposed arbitrators. The first party to strike-off a name shall be determined by lot. This process shall be repeated until one name remains on the list, and that individual shall be the designated arbitrator.

13.3.1.2 Disputes of \$1,000,000 or Over.

Where the total amount of claims and counterclaims in controversy is \$1,000,000 or more (exclusive of interest and costs), the disputing parties may agree on any person to serve as a single arbitrator, or shall endeavor in good faith to agree on a single arbitrator from a list of ten (10) qualified individuals provided by the ISO ADR Committee, or if the ISO is a party to the dispute, the names of at least ten (10) qualified individuals supplied by the American Arbitration Association within fourteen (14) days following submission of the demand for arbitration. If the parties are unable to agree on a single arbitrator within the stated time, the party or parties demanding arbitration, and the party or parties responding to the demand for arbitration, shall each designate an arbitrator. Each designation shall be from the ISO ADR Committee list of arbitrators no later than the tenth (10th) day thereafter. The two arbitrators so chosen shall then choose a third arbitrator.

13.3.2 Disclosures Required of Arbitrators.

The designated arbitrator(s) shall be required to disclose to the parties any circumstances which might preclude him or her from rendering an objective and impartial determination. Each designated arbitrator shall disclose:

13.3.2.1 Any direct financial or personal interest in the outcome of the arbitration;

13.3.2.2 Any information required to be disclosed by California Code of Civil Procedure Section 1281.9.; and

13.3.2.3 Any existing or past financial, business, professional, or personal interest that are likely to affect impartiality or might reasonably create an appearance of partiality or bias. The designated arbitrator shall disclose any such relationships that he or she personally has with any party or its counsel, or with any individual whom they have been told will be a witness. They should also disclose any such relationship involving members of their families or their current employers, partners, or business associates. All designated arbitrators shall make a reasonable effort to inform themselves of any interests or relationships described above. The obligation to disclose interests, relationships, or circumstances that might preclude an arbitrator from rendering an objective and impartial determination is a continuing duty that requires the arbitrator to disclose, at any stage of the arbitration, any such interests, relationships, or circumstances that arise, or are recalled or discovered. If, as a result of the continuing disclosure duty, an arbitrator makes a disclosure which is likely to affect his or her partiality, or might reasonably create an appearance of partiality or bias or if a party independently discovers the existence of such circumstances, a party wishing to object to the continuing use of the arbitrator must provide written notice of its objection to the other parties within ten (10) days of receipt of the arbitrator's disclosure or the date of a party's discovery of the circumstances giving rise to that party's objection. Failure to provide such notice shall be deemed a waiver of such objection. If a party timely provides a notice of objection to the continuing use of the arbitrator the parties shall attempt to agree whether the arbitrator should be dismissed and replaced in the manner described in Section 13.3.1. If within ten (10) days of a party's objection notice the parties have not agreed how to proceed the matter shall be referred to the ISO ADR Committee for resolution.

13.3.3 Arbitration Procedures.

The ISO ADR Committee shall compile and make available to the arbitrator and the parties standard procedures for the arbitration of disputes, which procedures (i) shall include provision, upon good cause

shown, for intervention or other participation in the proceeding by any party whose interests may be affected by its outcome, (ii) shall conform to the requirements specified herein, and (iii) may be modified or adopted for use in a particular proceeding as the arbitrator deems appropriate, in accordance with Section 13.3.4. The procedures adopted by the ISO ADR Committee shall be based on the latest edition of the American Arbitration Association Commercial Arbitration Rules, to the extent such rules are not inconsistent with this Section 13. Except as provided herein, all parties shall be bound by such procedures.

13.3.4 Modification of Arbitration Procedures.

In determining whether to modify the standard procedures for use in the pending matter, the arbitrator shall consider (i) the complexity of the dispute, (ii) the extent to which facts are disputed, (iii) the extent to which the credibility of witnesses is relevant to a resolution, (iv) the amount in controversy, and (v) any representations made by the parties. Alternatively, the parties may, by mutual agreement, modify the standard procedures. In the event of a disagreement between the arbitrator and the agreement of the parties regarding arbitration procedures to be utilized, the parties' agreement shall prevail.

13.3.5 Remedies.

13.3.5.1 Arbitrator's Discretion.

The arbitrator shall have the discretion to grant the relief sought by a party, or determine such other remedy as is appropriate, unless the parties agree to conduct the arbitration "baseball" style. Unless otherwise expressly limited herein, the arbitrator shall have the authority to award any remedy or relief available from FERC, or any other court of competent jurisdiction. Where any ISO Document leaves any matter to be agreed between the parties at some future time and provides that in default of agreement the matter shall be referred to the ISO ADR Procedures, the arbitrator shall have authority to decide upon the terms of the agreement which, in the arbitrator's opinion, it is reasonable that the parties should reach, having regard to the other terms of the ISO Document concerned and the arbitrator's opinion as to what is fair and reasonable in all the circumstances.

13.3.5.2 "Baseball" Arbitration.

If the parties agree to conduct the arbitration "baseball" style, the parties shall submit to the arbitrator and exchange with each other their last best offers in the form of the award they consider the arbitrator should make, not less than seven (7) days in advance of the date fixed for the hearing, or such other date as the arbitrator may decide. If a party fails to submit its last best offer in accordance with this Section, that party shall be deemed to have accepted the offer proposed by the other party. The arbitrator shall be limited to awarding only one of the proposed offers, and may not determine an alternative or compromise remedy.

13.3.6 Summary Disposition.

The procedures for arbitration of a dispute shall provide a means for summary disposition of a demand for arbitration, or a response to a demand for arbitration, that in the reasoned opinion of the arbitrator does not have a good faith basis in either law or fact. If the arbitrator determines that a demand for arbitration or response to a demand for arbitration does not have a good faith basis in either law or fact, the arbitrator shall have discretion to award the costs of the time, expenses, and other charges of the arbitrator to the prevailing party. A determination made under this Section is subject to appeal pursuant to Section 13.4.

13.3.7 Discovery Procedures.

The procedures for the arbitration of a dispute shall include adequate provision for the discovery of relevant facts, including the taking of testimony under oath, production of documents and other things, the presentation of evidence, the taking of samples, conducting of tests, and inspection of land and tangible items. The nature and extent of such discovery shall be determined as provided herein and shall take into account (i) the complexity of the dispute, (ii) the extent to which facts are disputed, (iii) the extent to which the credibility of witnesses is relevant to a resolution, and (iv) the amount in controversy. The forms and methods for taking such discovery shall be as described in the Federal Rules of Civil Procedure, except as modified pursuant to Section 13.3.4.

13.3.8 Evidentiary Hearing.

The arbitration procedures shall provide for an evidentiary hearing, with provision for the cross-examination of witnesses, unless all parties consent to the resolution of the matter on the basis of a written record. The forms and methods for taking evidence shall be determined by the arbitrator(s) and modified pursuant to Section 13.3.4. The arbitrator may require such written or other submissions from the parties as he or she may deem appropriate, including submission of direct and rebuttal testimony of witnesses in written form. The arbitrator may exclude any evidence that is irrelevant, immaterial, unduly repetitious or prejudicial, or privileged. The arbitrator shall compile a complete evidentiary record of the arbitration which shall be available to the parties on its completion upon request.

13.3.9 Confidentiality.

Subject to the other provisions of this ISO Tariff, any party may claim that information contained in a document otherwise subject to discovery is "Confidential" if such information would be so characterized under the Federal Rules of Evidence. The party making such claim shall provide to the arbitrator in writing the basis for its assertion. If the claim of confidentiality is confirmed by the arbitrator, he or she shall establish requirements for the protection of such documents or other information designated as "Confidential" as may be reasonable and necessary to protect the confidentiality and commercial value of such information. Any party disclosing information in violation of these provisions or requirements established by the arbitrator, unless such disclosure is required by federal or state law or by a court order, shall thereby waive any right to introduce or otherwise use such information in any judicial, regulatory, or other legal or dispute resolution proceeding, including the proceeding in which the information was obtained.

13.3.10 Timetable.

Promptly after the appointment of the arbitrator, the arbitrator shall set a date for the issuance of the arbitration decision, which shall be no later than six months (or such date as the parties and the arbitrator may agree) from the date of the appointment of the arbitrator, with other dates, including the dates for an evidentiary hearing or other final submissions of evidence, set in light of this date. The date for the

evidentiary hearing or other final submission of evidence shall not be changed, absent extraordinary circumstances. The arbitrator shall have the power to impose sanctions, including dismissal of the proceeding, for dilatory tactics or undue delay in completing the arbitration proceedings.

13.3.11 Decision.

13.3.11.1 Except as provided below with respect to "baseball" style arbitration, the arbitrator shall issue a written decision granting the relief requested by one of the parties, or such other remedy as is appropriate, if any, and shall include findings of fact and law. The arbitration decision shall be based on (i) the evidence in the record, (ii) the terms of the relevant ISO Documents, (iii) applicable United States federal law, including the FPA and any applicable FERC regulations and decisions, and international treaties or agreements as applicable, and (iv) applicable state law. Additionally, the arbitrator may consider relevant decisions in previous arbitration proceedings. A summary of the disputed matter and the arbitrator's decision shall be published in an ISO newsletter or electronic bulletin board and any other method adopted by the ISO ADR Committee, and maintained by the ISO ADR Committee.

13.3.11.2 In arbitration conducted "baseball" style, the arbitrator shall issue a written decision adopting one of the awards proposed by the parties, and shall include findings of fact and law. The arbitration decision shall be based on (i) the evidence in the record, (ii) the terms of the relevant ISO Documents, (iii) applicable United States federal law, including the FPA and any applicable FERC regulations and decisions, and international treaties or agreements as applicable, and (iv) applicable state law. If the arbitrator concludes that no proposed award is consistent with the factors enumerated in (i) through (iv) above, or addresses all of the issues in dispute, the arbitrator shall specify how each proposed award is deficient and direct that the parties submit new proposed awards that cure the identified deficiencies. A summary of the disputed matter and the arbitrator's decision shall be published in an ISO newsletter or electronic bulletin board, and any other method adopted by the ISO ADR Committee. An award shall not be deemed to be precedential.

13.3.11.3 Where a panel of arbitrators is appointed pursuant to Section 13.3.1.2, a majority of the arbitrators must agree on the decision.

13.3.12 Compliance.

Unless the arbitrator's decision is appealed under Section 13.4, the disputing parties shall, upon receipt of the decision, immediately take whatever action is required to comply with the award to the extent the award does not require regulatory action. An award that is not appealed shall be deemed to have the same force and effect as an order entered by the FERC or any court of competent jurisdiction.

13.3.13 Enforcement.

Following the expiration of the time for appeal of an award pursuant to Section 13.4.3, any party may apply to FERC or any court of competent jurisdiction for entry and enforcement of judgment based on the award.

13.3.14 Costs.

The costs of the time, expenses, and other charges of the arbitrator shall be borne by the parties to the dispute, with each side on an arbitrated issue bearing its pro-rata share of such costs, and each party to an arbitration proceeding bearing its own costs and fees. If the arbitrator determines that a demand for arbitration or response to a demand for arbitration was made in bad faith, the arbitrator shall have discretion to award the costs of the time, expenses, and other charges of the arbitrator to the prevailing party. Notwithstanding the above, at the discretion of the arbitrator, the winning party in any dispute which has resulted in the enforcement of an important right affecting the public interest shall not be required to pay any of the costs of the arbitrator and may recover such of its own reasonable attorney fees, expert witness fees and other reasonable costs from the losing party to the dispute if (a) a significant benefit, whether pecuniary or non-pecuniary, has been conferred on the general public, (b) the necessity and financial burden of private enforcement are such as to make the award appropriate, and (c) such fees should not, in the interest of justice, be paid out of the recovery.

13.4 Appeal of Award.

13.4.1 Basis for Appeal.

A party may apply to the FERC or any court of competent jurisdiction to hear an appeal of an arbitration award only upon the grounds that the award is contrary to or beyond the scope of the relevant ISO

Documents, United States federal law, including, without limitation, the FPA, and any FERC regulations and decisions, or state law. Appeals shall, unless otherwise ordered by FERC or the court of competent jurisdiction, conform to the procedural limitations set forth in this Section 13.4.

13.4.2 Appellate Record.

The parties intend that FERC or the court of competent jurisdiction should afford substantial deference to the factual findings of the arbitrator. No party shall seek to expand the record before the FERC or court of competent jurisdiction beyond that assembled by the arbitrator, except (i) by making reference to legal authority which did not exist at the time of the arbitrator's decision, or (ii) if such party contends the decision was based upon or affected by fraud, collusion, corruption, misconduct or misrepresentation.

13.4.3 Procedures for Appeals.

13.4.3.1 If a party to an arbitration desires to appeal an award, it shall provide a notice of appeal to the ISO Governing Board, all parties and the arbitrator within 14 days following the date of the award. The appealing party must likewise provide notice to the ISO ADR Committee, which shall publish notice of the appeal in an ISO newsletter or on WEnet, and any other method adopted by the ISO ADR Committee.

Within ten (10) days of the filing of the notice of appeal, the appealing party must file an appropriate application, petition or motion with the FERC to trigger review under the FPA or with a court of competent jurisdiction. Such filing shall state that the subject matter has been the subject of an arbitration pursuant to the relevant ISO Document.

13.4.3.2 Within 30 days of filing the notice of appeal (or such period as FERC or the court of competent jurisdiction may specify) the appellant shall file the complete evidentiary record of the arbitration and a copy of the award with FERC or with the court of competent jurisdiction. The appellant shall serve copies of a description of all materials included in the submitted evidentiary record.

13.4.4 Award Implementation.

Implementation of the award shall be deemed stayed pending an appeal unless and until, at the request of a party, the FERC or the court of competent jurisdiction to which an appeal has been filed, issues an

order dissolving, shortening, or extending such stay. However, a summary of each appeal shall be published in an ISO newsletter or electronic bulletin board, and any other method adopted by the ISO ADR Committee.

13.4.5 Judicial Review of FERC Orders.

FERC orders resulting from appeals shall be subject to judicial review pursuant to the FPA.

13.5 Allocation of Awards Payable by or to the ISO.

13.5.1 Allocation of an Award.

If the ISO must pay an award to a party pursuant to good faith negotiations or the ISO ADR Procedures, the ISO will recover the amount of the award from Market Participants and Scheduling Coordinators. If the ISO receives an award from a party pursuant to good faith negotiations or the ISO ADR Procedures, the ISO will flow back the amount of the award to Market Participants and Scheduling Coordinators.

13.5.2 Timing of Adjustments.

Upon determination that an award is payable by or to the ISO pursuant to good faith negotiations or the ISO ADR Procedures, the ISO shall calculate the amounts payable to and receivable from the party, Market Participants, and Scheduling Coordinators, as soon as reasonably practical, and shall show any required adjustments as a debit or a credit in a subsequent Preliminary Settlement Statement or, in the case of an amount payable by the ISO to a party, as soon as the ISO and that party may agree.

13.5.3 Method of Allocation.

13.5.3.1 Allocation to Market Participants.

The ISO will use best efforts to determine which Market Participant(s) is or are responsible for and/or benefit from payment of an award by or to the ISO and to allocate receipt of or payment for the award equitably to such Market Participant(s). In undertaking the allocation, the ISO shall consider the extent of a Market Participant's participation in affected markets and the ISO Tariff in effect on the applicable Trading Day(s), and may consider any other relevant factor, including but not limited to, applicable contracts.

13.5.3.2 Residual Amounts.

Any awards for which the ISO is unable to identify Market Participants in accordance with 13.5.3.1 and any award amounts that the ISO is unable to collect that are not covered by Section 11.16.1 will be allocated to all Scheduling Coordinators through Neutrality Adjustments.

14 FORCE MAJURE INDEMNIFICATION AND LIMITATIONS ON LIABILITY.

14.1 Uncontrollable Forces.

14.1.1 An Uncontrollable Force means 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. Neither the ISO nor a Market Participant will be considered in default of any obligation under this ISO Tariff if prevented from fulfilling that obligation due to the occurrence of an Uncontrollable Force.

14.1.2 In the event of the occurrence of an Uncontrollable Force, which prevents the ISO or a Market Participant from performing any of its obligations under this ISO Tariff, the affected entity shall (i) if it is the ISO, immediately notify the Market Participants in writing of the occurrence of such Uncontrollable Force and, if it is a Market Participant, immediately notify the ISO in writing of the occurrence of such Uncontrollable Force, (ii) not be entitled to suspend performance of its obligations under this ISO Tariff in any greater scope or for any longer duration than is required by the Uncontrollable Force, (iii) use its best efforts to mitigate the effects of such Uncontrollable Force, remedy its inability to perform and resume full performance of its obligations hereunder, (iv) in the case of the ISO, keep the Market Participants apprised of such efforts, and in the case of the Market Participants, keep the ISO apprised of such efforts, in each case on a continual basis and (v) provide written notice of the resumption of its performance of its obligations hereunder.

Notwithstanding any of the foregoing, the settlement of any strike, lockout or labor dispute constituting an Uncontrollable Force shall be within the sole discretion of the entity involved in such strike, lockout or

labor dispute and the requirement that an entity must use its best efforts to mitigate the effects of the Uncontrollable Force and/or remedy its inability to perform and resume full performance of its obligations hereunder shall not apply to strikes, lockouts, or labor disputes.

14.2 Market Participant's Indemnity.

Each Market Participant, to the extent permitted by law, shall indemnify the ISO and hold it harmless against all losses, damages, claims, liabilities, costs or expenses (including legal expenses) arising from any act or omission of the Market Participant except to the extent that they result from the ISO's default under this ISO Tariff or negligence or intentional wrongdoing on the part of the ISO or of its officers, directors or employees.

14.3 Limitation on Liability.

14.3.1 Liability for Damages.

Except as provided for in Section 13.3.14, the ISO shall not be liable in damages to any Market Participant for any losses, damages, claims, liability, costs or expenses (including legal expenses) arising from the performance or non-performance of its obligations under this ISO Tariff, including but not limited to any adjustments made by the ISO in Inter-Scheduling Coordinator Trades, except to the extent that they result from negligence or intentional wrongdoing on the part of the ISO.

14.3.2 Exclusion of Certain Types of Loss.

The ISO shall not be liable to any Market Participant under any circumstances for any consequential or indirect financial loss including but not limited to loss of profit, loss of earnings or revenue, loss of use, loss of contract or loss of goodwill except to the extent that it results from except to the extent that it results from negligence or intentional wrongdoing on the part of the ISO.

14.4 Potomac Economics, Ltd. Limitation Of Liability.

Potomac Economics, Ltd. shall not be liable in damages to any Market Participant for any losses, damages, claims, liability, costs or expenses (including legal expenses) arising from its calculation of

reference levels under its Consultant Agreement with the ISO dated as of September 3, 2002, except to the extent that they result from negligence or intentional wrongdoing of Potomac Economics, Ltd.

15 REGULATORY FILINGS.

Any amendment or other modification of any provision of this ISO Tariff must be in writing and approved by the ISO Governing Board in accordance with the bylaws of the ISO. Any such amendment or modification shall be effective upon the date it is permitted to become effective by FERC. Nothing contained herein shall be construed as affecting, in any way, the right of the ISO to furnish its services in accordance with this ISO Tariff, or any tariff, rate schedule or Scheduling Coordinator Agreement which results from or incorporates this ISO Tariff, unilaterally to make an application to FERC for a change in rates, terms, conditions, charges, classifications of service, Scheduling Coordinator Agreement, rule or regulation under FPA Section 205 and pursuant to the FERC's rules and regulations promulgated thereunder. Nothing contained in this ISO Tariff or any Scheduling Coordinator Agreement shall be construed as affecting the ability of any Market Participant receiving service under this ISO Tariff to exercise its rights under Section 206 of the FPA and FERC's rules and regulations thereunder.

16 EXISTING CONTRACTS.

16.1 Existing Contracts for Transmission Service.

16.1.1 In accordance with Section 16.2 each Participating TO and holder of transmission rights under an Existing Contract will work with the ISO to develop operational protocols (which shall be based on existing protocols and procedures to the extent possible) which allow existing contractual rights to be exercised in accordance with Section 16.2 in a way that: (i) maintains the existing scheduling and curtailment priorities under the Existing Contract; (ii) is minimally burdensome to the ISO (i.e., creates the least impact on the ISO's preferred operational protocols, rules and procedures); (iii) to the extent possible, imposes no additional financial burden on either the Participating TO or the contract rights holder (beyond that in the Existing Contract); (iv) consistent with the terms of the Existing Contracts, makes as much transmission capacity not otherwise utilized by the holder of the transmission rights as possible available to the ISO for allocation to Market Participants; (v) is minimally burdensome to the

Participating TO and the holder of the transmission rights from an operational point of view; and (vi) does not require the ISO to interpret or underwrite the economics of the Existing Contract.

16.1.2 The ISO will accept valid Schedules from a Responsible Participating TO that is the Scheduling Coordinator for the Existing Contract rights holders, or from Existing Contract rights holders that are Scheduling Coordinators, or that are represented by a Scheduling Coordinator other than the Responsible Participating TO. Schedules submitted by Scheduling Coordinators to the ISO which include the use of Existing Rights must be submitted in accordance with Section 16.1, Section 16.2, and Section 30.2.7. The ISO may refuse to accept Schedules submitted pursuant to Existing Contracts which do not meet the requirements of the principles, protocols and rules referred to in this Section 16.1 and Section 16.2. The ISO will implement Sections 16.1 and 16.2 with respect to Existing Contracts after the close of the Hour-Ahead Market and in real time.

16.1.3 The ISO will, if requested, advise parties to Existing Contracts regarding the operational aspects of any Existing Contract renegotiations that they undertake.

16.2 ISO Administration of Existing Contracts for Transmission Service.

16.2.1 Continuation of Rights and Obligations of Non-Participating TOs Under Existing Contracts.

16.2.1.1 The transmission service rights and obligations of Non-Participating TOs under Existing Contracts, including all terms, conditions and rates of the Existing Contracts, as they may change from time to time under the terms of the Existing Contracts, will continue to be honored by the parties to those contracts, for the duration of those contracts. For the purpose of Section 16.2, the transmission service rights of Non-Participating TOs are called "Existing Rights."

16.2.1.2 If a Participating TO is a party to an Existing Contract under which Existing Rights are provided, the Participating TO shall attempt to negotiate changes to the Existing Contract to align the contract's scheduling and operating provisions with the ISO's scheduling and operational procedures, rules and protocols, to align operations under the contract with ISO operations, and to minimize the

contract parties' costs of administering the contract while preserving their financial rights and obligations as defined in Section 16.2.2.

In addition, the Participating TO shall attempt to negotiate changes to provisions in the Existing Contract to ensure that whenever transmission services under the Existing Contract are used to deliver power to a Market Participant that is subject to Access Charges under this Tariff, no duplicative charge for access to the ISO Controlled Grid will be charged under the Existing Contract. For purposes of such negotiations, there shall be a presumption that any charges in an Existing Contract that were designed to recover the embedded cost of transmission facilities within the ISO Controlled Grid will be fully recovered through the Access Charges established under Section 26.1 of this Tariff.

16.2.1.3 If a Non-Participating TO has an Existing Contract with a Participating TO under which the Non-Participating TO's transmission facilities are subject to use by the Participating TO, the Non-Participating TO's rights to the use and ownership of its facilities shall remain unchanged, regardless of the Participating TO's act of turning over the Participating TO's entitlement to use the Non-Participating TO's facilities to the extent possible to the Operational Control of the ISO.

16.2.1.4 If the parties to an Existing Contract are unable to reach agreement on the changes needed to meet the requirements of Section 16.2.1.2 or Section 16.2.1.3, any disputes related thereto shall be addressed using the dispute resolution provisions of the Existing Contract, including any remedies as are provided by law. The rights of the parties to seek changes or to challenge such changes, under the FPA or as otherwise provided by law, are preserved consistent with the terms of the Existing Contract. Unless and until the necessary changes to the Existing Contract are made, all terms and conditions of the Existing Contracts will continue to be honored by the parties to the contracts.

16.2.1A Conversion of Participating TOs' Rights and Obligations Under Existing Contracts.

16.2.1A.1 Parties who are entitled to transmission service rights under Existing Contracts and who choose to become Participating TOs must, at the time of becoming a Participating TO exercise those rights by converting them to "Converted Rights", which are described in Section 16.2.2. A party who ceases to be a Participating TO at or before the end of the five year period beginning at the ISO Operations Date shall be entitled to resume service under any Existing Contract to which it is then a

party, so long as that contract has not expired or been terminated. For the purposes of Sections 16.1 and 16.2, Pacific Gas & Electric Company, Southern California Edison Company and San Diego Gas & Electric Company will be deemed to have converted all rights that they may hold under Existing Contracts to Converted Rights as described in Section 16.2.2 with effect from the ISO Operations Date. Schedules that utilize Converted Rights shall be submitted by a Scheduling Coordinator that has been certified in accordance with Section 4.5.1.

16.2.1A.2 As part of the conversion referred to in Section 16.2.1A.1, modifications to an Existing Contract may be needed. Any required modifications must be agreed upon by all parties to the contract. Failure of the parties to reach agreement on the modifications required under Section 16.2.1A.1 shall be addressed using the dispute resolution provisions of the Existing Contract, including any remedies as are provided by law consistent with the terms of the Existing Contract. The rights of the parties to challenge such changes, under the FPA or as otherwise provided by law, are preserved.

16.2.2 Converted Rights.

16.2.2.1 A recipient of transmission service under an Existing Contract that chooses to become a Participating TO and convert its rights to ISO transmission service, and the Participating TO which provides the transmission service under the Existing Contract shall change the terms and conditions of the contract to provide that:

16.2.2.1.1 The recipient of the transmission service received under an Existing Contract that has converted its rights to ISO transmission service shall turn over Operational Control of its transmission entitlement to the ISO for management by the ISO in accordance with the ISO's scheduling, Congestion Management, curtailment and other ISO Protocols;

16.2.2.1.2 The recipient of the transmission service under an Existing Contract that has converted its rights to ISO transmission service shall obtain all future transmission services within, into (starting at the ISO Controlled Grid), out of, or through the ISO Controlled Grid using the ISO's scheduling and operational procedures and protocols and the ISO Tariff and any applicable TO Tariff, provided that this provision shall not affect the rights, if any, of the contract parties to extend Existing Contracts.

16.2.2.1.3 [Not Used]

16.2.2.1.4 For the capacity represented by its rights, the recipient of firm transmission service under an Existing Contract that has converted its rights to ISO transmission service shall be entitled to receive the Usage Charge revenues for the capacity (and/or alternatives to such revenues, such as physical transmission rights or transmission congestion contracts, should they exist) and all Wheeling revenue credits throughout the term that the capacity is available under the Existing Contract. The recipient of less than firm service shall receive these revenues in proportion to the degree of firmness and the terms and conditions of their service.

16.2.2.1.5 The recipient of the transmission service received under an Existing Contract that has converted its rights to ISO transmission service shall continue to have the obligation to pay the provider of the service for its transmission service at the rates provided in the Existing Contract, as they may change from time to time under the terms of the Existing Contract, or as mutually agreed between the contract parties, through the term of the contract, subject to the terms and conditions of the contract, including the rights of the parties to the contract to seek unilateral or other changes pursuant to Section 205 or Section 206 of the Federal Power Act and the FERC's Rules and Regulations or as otherwise provided by law.

16.2.2.2 Other aspects of such an Existing Contract may also need to be changed. If the parties to the contract are unable to negotiate such changes, they shall seek appropriate changes through the mechanisms provided within the contract, including the rights, if any, to seek unilateral or other changes pursuant to Section 205 or Section 206 of the Federal Power Act and the FERC's Rules and Regulations or as otherwise provided by law.

16.2.3 ISO Treatment of Non-Participating TOs Existing Rights.

16.2.3.1 For the purposes of Section 16.2, Existing Rights fall into one of three general categories: firm transmission service, non-firm transmission service, and conditional firm transmission service. The parties to an Existing Contract shall notify the ISO which Existing Rights fall into each category, through the operating instructions described in this section and in Section 16.2.4A.

- (i) For each Existing Contract, the party providing transmission service (the “Responsible PTO”) shall be responsible for the submission of transmission rights/curtailment instructions to the ISO on behalf of the holders of Existing Rights, unless the parties to the Existing Contract agree otherwise. For the purposes of this ISO Tariff, such otherwise agreed party will be acting in the role of Responsible PTO.
- (ii) In accordance with the ISO Tariff, the parties to Existing Contracts will attempt to jointly develop and agree on any instructions that will be submitted to the ISO. To the extent there is more than one Participating TO providing transmission service under an Existing Contract or there is a set of Existing Contracts which are interdependent from the point of view of submitting instructions to the ISO involving more than one Participating TO, the relevant Participating TOs will designate a single Participating TO as the Responsible PTO and will notify the ISO accordingly. If no such Responsible PTO is designated by the relevant Participating TOs or the ISO is not notified of such designation, the ISO shall designate one of them as the Responsible PTO and notify the relevant Participating TOs accordingly.
- (iii) The parties to an Existing Contract shall also be responsible to submit to the ISO any other necessary operating instructions based on their contract interpretations needed by the ISO to enable the ISO to perform its duties.

16.2.3.1.1 The ISO will have no role in interpreting Existing Contracts. The parties to an Existing Contract will, in the first instance, attempt jointly to agree on any operating instructions that will be submitted to the ISO. In the event that the parties to the Existing Contract cannot agree upon the operating instructions submitted by the parties to the Existing Contract, the dispute resolution provisions of the Existing Contract, if applicable, shall be used to resolve the dispute; provided that, until the dispute is resolved, and unless the Existing Contract specifies otherwise, the ISO shall implement the Participating TO’s operating instructions. If both parties to an Existing Contract are Participating TOs and the parties cannot agree to the operating instructions submitted by the parties, until the dispute is

resolved, and unless the Existing Contract specifies otherwise, the ISO shall implement the operating instructions of the first Participating TO for which the Existing Contract is an Encumbrance.

16.2.3.2 The ISO's scheduling protocols will accommodate Existing Rights, so that the holders of Existing Rights will receive the same priorities (in scheduling, curtailment, assignment and other aspects of transmission system usage) to which they are entitled under their Existing Contracts.

16.2.3.3 Scheduling deadlines and operational procedures associated with Existing Rights will be honored by the ISO.

16.2.3.4 All contractual provisions that have been communicated to the ISO in writing in accordance with Section 16.2.3.1 by the parties to the Existing Contracts, shall be honored by the ISO and the parties to the Existing Contracts and shall be implemented in accordance with the terms and conditions of the relevant Existing Contracts so notified.

16.2.3.4.1 The holders of Existing Rights will not be responsible for paying Usage Charges related to those rights, nor will they be entitled to receive Usage Charge revenues related to those rights.

16.2.3.4.2 Other than any existing rights to such revenues under the Existing Contracts, the holders of Existing Rights will not be entitled to an allocation of revenues from Wheeling Out or Wheeling Through services on the ISO Controlled Grid, related to those rights.

16.2.3.4.3 The holders of Existing Rights shall continue to pay the providers of the Existing Rights at the rates provided in the associated Existing Contracts, as they may change from time to time under the terms of the Existing Contracts.

16.2.3.4.4 **[Not Used]**

16.2.3.4.5 Parties with Existing Rights shall continue to pay for Transmission Losses or Ancillary Services requirements in accordance with such Existing Contracts as they may be modified or changed in accordance with the terms of the Existing Contract. Likewise the Participating TOs shall continue to provide Transmission Losses and any other Ancillary Services to the holder of the rights under an Existing Contract as may be required by the Existing Contracts. To the extent that Transmission Losses or Ancillary Service requirements associated with Existing Rights are not the same as those under the

ISO's rules and protocols, the ISO will not charge or credit the Participating TO for any cost differences between the two, but will provide the parties to the Existing Contracts with details of its Transmission Losses and Ancillary Services calculations to enable them to determine whether the ISO's calculations result in any associated shortfall or surplus and to enable the parties to the Existing Contracts to settle the differences bilaterally or through the relevant TO Tariff. Each Participating TO will be responsible for recovering any deficits or crediting any surpluses associated with differences in assignment of Transmission Loss requirements and/or Ancillary Services requirements, through its bilateral arrangements or its Transmission Owner's Tariff.

16.2.4 ISO Protocols Shall Accommodate Existing Rights.

The ISO will implement the provisions of Section 16.2.3. The objective will be to ensure that under the ISO Tariff, Existing Rights will enjoy the same relative priorities vis-à-vis new, ISO-provided transmission uses, as they would under the Existing Contracts and the FERC Order 888 tariffs. Under the ISO Tariff:

16.2.4A Existing scheduling rules, curtailment priorities and any other relevant terms and conditions associated with the scheduling and day-to-day implementation of transmission rights will be documented in sets of operating instructions provided to the ISO by the parties to the Existing Contracts. The documentation of these operating instructions, and disputes related to these operating instructions, will be handled in accordance with the terms of Section 16.2.3.1.1.

16.2.4A.1 The responsible Participating TO with respect to an Existing Contract or set of interdependent Existing Contracts is required to submit to the ISO, in accordance with the timing requirements of Section 16.2.4A.2 and 16.2.4A.3, the instructions that are necessary to implement the exercise of Existing Rights in accordance with the ISO Tariff. The operating instructions will be submitted to the ISO electronically, by the Responsible PTO, utilizing a form provided by the ISO in a format similar to the one set out in the Standard Template – Transmission Rights/Curtailment Instructions in Appendix M. The instructions will include the following information at a minimum and such other information as the ISO may reasonably require to enable it to carry out its functions under the ISO Tariff and ISO Protocols (the letters below correspond with the letters of the instructions template in the Standard Template – Transmission Rights/Curtailment Instructions in Appendix M:

- (a) a unique contract reference number (Existing Contract reference number that will be assigned by the ISO and communicated to the Responsible PTO on the completed instruction and that references a single Existing Contract or a set of interdependent Existing Contracts; the provisions of Section 30.4.2 will apply to the validation of scheduled uses of Existing Contract transmission rights);
- (b) whether the instruction can be exercised independent of the ISO's day-to-day involvement (Yes/No);
- (c) name of an operational single point of contact for instructions and a 24-hour a day telephone number for the Responsible PTO;
- (d) name(s) and number(s) of Existing Contract(s);
- (e) path name(s) and location(s) (described in terms of the Zones in which the point(s) of receipt and point(s) of delivery are located);
- (f) names of the party(ies) to the Existing Contract(s);
- (g) Scheduling Coordinator ID code: the ID number of the Scheduling Coordinator who will submit Schedules which make use of the Existing Contract(s) for the party(ies) indicated in (f);
- (h) type(s) of rights, by rights holder, by Existing Rights;
- (i) type(s) of service, by rights holder, by Existing Contract (firm, conditional firm, or non-firm), with priorities for firm and conditional firm transmission services indicated in Schedules using Adjustment Bids as described in this ISO Tariff;
- (j) amount of transmission service, by rights holder, by Existing Contract expressed in MW;
- (k) for Day-Ahead scheduling purposes, the time of the day preceding the Trading Day at which the Scheduling Coordinator submits Schedules to the ISO referencing the Existing Contract(s) identified in the instructions;

- (l) for Hour-Ahead or real-time scheduling purposes, the number of minutes prior to the start of the Settlement Period of delivery at which the Scheduling Coordinator may submit Schedule adjustments to the ISO regarding the Existing Rights under the Existing Contract(s) identified in the instructions;
- (m) whether or not real-time modifications to Schedules associated with Existing Rights are allowed at any time during the Settlement Period;
- (n) Service period(s) of the Existing Contract(s);
- (o) any special procedures which would require curtailments to be implemented by the ISO in any manner different than that specified in Section 7.4.12. Any such instructions submitted to the ISO must be clear, unambiguous, and not require the ISO to make any judgments or interpretations as to the meaning intent, results, or purpose of the curtailment procedures or the Existing Contract (otherwise, they will not be accepted by the ISO); and
- (p) any special procedures relating to curtailments during emergency conditions. Any such instructions submitted to the ISO must be clear, unambiguous, and not require the ISO to make any judgments or interpretations as to the meaning, intent, results, or purpose of the curtailment procedures or the Existing Contract (otherwise, they will not be accepted by the ISO).

16.2.4A.2 The Responsible PTOs shall submit the operating instructions to the ISO associated with Existing Contracts or sets of interdependent Existing Contracts thirty (30) days prior to either (a) the ISO Operations Date or (b) the date on which the scheduling or curtailment of the use of the Existing Rights is to commence pursuant to Sections 16.1 or 16.2. The ISO will not accept Schedules which include the use of Existing Rights, unless the Responsible PTO has provided the ISO with the information required in the Transmission Control Agreement and this Section 16.2.4, including transmission rights/curtailment instructions supplied in a form and by means of communication specified by the ISO.

16.2.4A.3 Updates or changes to the operating instructions must be submitted to the ISO by the Responsible PTO, on an as needed or as required basis determined by the parties to the Existing Contracts. The ISO will implement the updated or changed instructions as soon as practicable but not later than seven (7) days after receiving clear and unambiguous details of the updated or changed instructions. If the ISO finds the instructions to be inconsistent with respect to the ISO Protocols or the ISO Tariff, the ISO will notify the Responsible PTO within forty-eight (48) hours after receipt of the updated or changed instructions indicating the nature of the problem and allowing the Responsible PTO to resubmit the instructions as if they were new, updated or changed instructions. If the ISO finds the updated or changed instructions to be acceptable, the ISO will time-stamp the updated instructions as received, confirm such receipt to the Responsible PTO, and indicate the time at which the updated instructions take effect if prior to the seven (7) day deadline referred to above.

16.2.4B To the extent that the operating instructions can be exercised independently of the ISO by the parties to the Existing Contract and the results forwarded to the ISO, the operating instructions shall be exercised by the Participating TOs, and the outcomes shall be forwarded to the ISO. The determination of whether the operating instructions can be “exercised independently of the ISO by the parties to the Existing Contract” shall be made using the same procedures described in Section 16.2.3.1.1.

16.2.4C To the extent that the operating instructions can not be exercised independently of the ISO and the results forwarded to the ISO (because, for example, they require iteration with the ISO’s scheduling process, would unduly interfere with the ISO’s real-time management of curtailments or would unduly interfere with the ability of the holder of rights to exercise its rights), the operating instructions will be provided to the ISO for day-to-day implementation. These instructions will be provided by the Responsible PTO to the ISO for implementation unless the parties to the Existing Contracts otherwise agree that the rights holder will do so. For these instructions, the Scheduling Coordinators representing the holders of Existing Rights will submit their Schedules to the ISO for implementation in accordance with the instructions. In this case, the ISO shall act as the scheduling agent for the Participating TOs with regard to Existing Rights.

16.2.4D The ISO shall determine, based on the information provided by the Participating TOs and contract rights holders under Sections 16.2.4B and 16.2.4C, the transmission capacities that (i) must be reserved for firm Existing Rights, (ii) may be allocated for use as ISO transmission service (i.e., new firm uses), (iii) must be reserved by the ISO for conditional firm Existing Rights, and (iv) remain for any non-firm Existing Rights for which a Participating TO has no discretion over whether or not to provide such non-firm service.

16.2.4E The ISO shall coordinate the scheduling of Existing Rights with the scheduling of ISO transmission service, using the ISO's Day-Ahead scheduling rules and protocols. In doing so, the ISO shall subtract, from the capacity that is available for the ISO to schedule in the ISO's Day-Ahead scheduling process, an appropriate amount of transmission capacity reflecting the amount and nature of the Existing Rights.

16.2.4F For those Existing Rights the use of which has not been scheduled by the rights-holders by the start of the ISO's Hour-Ahead scheduling process, the ISO shall coordinate the scheduling of Existing Rights with the scheduling of ISO transmission service, using the ISO's Hour-Ahead scheduling protocols. In doing so, the ISO may, at its own discretion, consider as available for the ISO to schedule in its Hour-Ahead scheduling process, any or all of the transmission capacity associated with Existing Rights the use of which has not been scheduled by the rights-holders in the ISO's Hour-Ahead scheduling process.

16.2.4G The ISO shall recognize that the obligations, terms or conditions of Existing Contracts may not be changed without the voluntary consent of all parties to the contract (unless such contract may be changed pursuant to any applicable dispute resolution provisions in the contract or pursuant to Section 205 or Section 206 of the FPA and the FERC's Rules and Regulations or as otherwise provided by law).

16.2.4H The parties to Existing Contracts shall remain liable for their performance under the Existing Contracts. The ISO shall be liable in accordance with the provisions of this ISO Tariff for any damage or injury caused by its non-compliance with the operating instructions submitted to it pursuant to this Section 16.2.

16.2.4I Unless specified otherwise, in the event that the dispute resolution mechanisms prescribed in an Existing Contract, including all recourses legally available under the contract, can not, in the first instance, result in a resolution of such a dispute, the ISO's ADR Procedure will be used to resolve any disputes between the ISO and the Participating TO regarding any aspects of the implementation of Section 16.1 and 16.2, including the reasonableness of a Participating TO's operating instructions or any other decision rules which the Participating TO may submit to the ISO as part of the operational protocols. The transmission rights-holder(s) under the Existing Contract shall have standing to participate in the ISO ADR Procedure.

16.2.4.1 Allocation of Forecasted Total Transfer Capabilities.

16.2.4.1.1 Prioritization of Transmission Uses.

The following rules are designed to enable the ISO to honor Existing Contracts in accordance with Sections 16.1 and 16.2 of the ISO Tariff. Regardless of the success of the application of such rules, it is intended that the rights under Existing Contracts will be honored as contemplated by the ISO Tariff. In each of the categories described in Section 23, the terms and conditions of service may differ among transmission contracts. These differences will be described by each Responsible PTO in the instructions submitted to the ISO in advance of the scheduling process. In addition, Generation, Inter-Scheduling Coordinator Energy Trade imports or external imports in one Zone must be matched by an equal magnitude of Demand, Inter-Scheduling Coordinator Energy Trade exports or external exports in an adjacent Zone (see Section 16.2.4.1.2 for a summary of allowable linkages). Scheduling and curtailment priorities associated with each category will be defined by Scheduling Coordinators through the use of contract usage templates submitted as part of their Schedules.

(a) Transmission capacity for Schedules will be made available to holders of firm Existing Rights in accordance with this Section and the terms and conditions of their Existing Contracts. In the event that the firm uses of these rights must be curtailed, they will be curtailed on the basis of priority expressed in contract usage templates. So as not to be curtailed before any other scheduled use of Congested Inter-Zonal Interface capacity, the ISO's Congestion Management software will assign high priced Adjustment Bids to the scheduled uses (for example, a difference of \$130,000/MWh to \$140,000/MWh for Demand or

external exports and a difference of $-\$130,000/\text{MWh}$ to $-\$140,000/\text{MWh}$ for Generation or external imports). This range will be reserved strictly for use in association with the prioritization of firm Existing Rights to use available Inter-Zonal Interface transmission capacity. These high priced Adjustment Bids are only for the ISO's use, in the context of Inter-Zonal Congestion Management, in recognizing the various levels of priority that may exist among the scheduled uses of firm transmission service. These high priced Adjustment Bids will not affect any other rights under Existing Contracts. To the extent that the MW amount exceeds the MW amount specified in the Existing Contract, the excess scheduled amount will be treated as a new firm use of ISO transmission services as described in (b) below. Note that, in some instances, for a particular Inter-Zonal Interface, there may be multiple Scheduling Coordinators submitting Schedules under several different Existing Contracts on behalf of several Existing Contract rights holders. In these circumstances, and to the extent the rights holders desire to coordinate the prioritization of their firm uses of the Inter-Zonal Interface, their Scheduling Coordinators will make the arrangements among themselves ahead of the ISO's scheduling process. In the absence of a valid contract usage template associated with Existing Contract rights, the ISO will treat the scheduled use of transmission service as a "price-taker" of ISO transmission service subject to Usage Charges.

(b) ISO transmission service (i.e., "new firm uses") will be priced in accordance with the ISO Tariff. Usage Charges associated with the ISO's Congestion Management procedures, as described in Section 27.1.1.5, will be based on Adjustment Bids. In the absence of an Adjustment Bid, the ISO will treat the scheduled "new firm use" of ISO transmission service as a price taker paying the Usage Charge established by the highest valued use of transmission capacity between the relevant Zones.

(c) Transmission capacity will be made available to holders of conditional firm Existing Rights in a manner similar to that done prior to the ISO Operations Date; that is, allocated, as available, based on the agreed priority. The levels of priority will be expressed in the contract usage templates associated with the Schedules. To the extent that the MW amount in a schedule exceeds the MW amount specified in the contract usage template, the excess scheduled amount will be treated as a new firm use of ISO transmission services as described in (b) above. Note that, in some instances, for a particular Inter-Zonal Interface, there may be multiple Scheduling Coordinators submitting Schedules under several different

Existing Contracts on behalf of several Existing Contract rights holders. In these circumstances, and to the extent the rights holders desire to coordinate the prioritization of their conditional firm uses of the Inter-Zonal Interface, their Scheduling Coordinators will make the arrangements among themselves ahead of the ISO's scheduling process. In the absence of a valid contract usage template associated with Existing Contract rights, the ISO will treat the scheduled use of transmission service as a "price-taker" of ISO transmission services subject to Usage Charges.

(d) Transmission capacity will be made available to holders of non-firm Existing Rights in a manner similar to that done prior to the ISO Operations Date; that is, treated as the lowest valued use of available transmission capacity. Non-firm uses of transmission capacity under Existing Contracts will be indicated in Schedules submitted by Scheduling Coordinators as \$0.00/MWh Adjustment Bids. Therefore, there will be no contract reference number associated with non-firm Existing Contract rights.

16.2.4.1.2 Allowable Linkages.

As indicated in Section 16.2.4.1.1, Generation, Inter-Scheduling Coordinator Energy Trade imports or external imports in one Zone must be matched by an equal magnitude of Demand, Inter-Scheduling Coordinator Energy Trade exports or external exports in the same Zone or in an adjacent Zone.

16.2.4.2 The Day-Ahead Process.

16.2.4.2.1 Validation.

The ISO will coordinate the scheduling of the use of Existing Rights with new firm uses in the Day-Ahead process. The ISO will validate the Schedules submitted by Scheduling Coordinators on behalf of the rights holders for conformity with the instructions previously provided by the Responsible PTO. Invalid Schedules will be rejected and the ISO will immediately communicate the results of each Scheduling Coordinator's validation to that Scheduling Coordinator via WEnet.

16.2.4.2.2 Scheduling Deadlines.

Those Existing Contract rights holders who must schedule the use of their rights by the deadline for the submission of Schedules in the Day-Ahead Market must do so. After this time, the ISO will release these unused rights as available for new firm uses (not subject to recall).

16.2.4.2.3 Reservation of Firm Transmission Capacity.

As an initial step in performing its Day-Ahead Congestion Management analysis, the ISO will determine the amount of transmission capacity that is available by subtracting, from the total transfer capability of the Inter-Zonal Interface, the unused portions of capacity applicable to firm Existing Rights. For purposes of Congestion Management, the total transfer capability of the Inter-Zonal Interface is therefore adjusted downward by an amount equal to the unused portions of firm Existing Rights. By reserving these blocks of unused transmission capacity, Existing Contracts rights holders are able to schedule the use of their transmission service on the timelines provided in their Existing Contracts after the deadline of the ISO's Day-Ahead scheduling process (in other words, after 1:00 pm on the day preceding the Trading Day), but prior to the deadline of the ISO's Hour-Ahead scheduling process (in other words, two hours ahead of the Settlement Period).

16.2.4.2.4 Allocation of Inter-Zonal Interface Capacities.

In the ISO's Congestion Management analysis of the Day-Ahead Market, for each Inter-Zonal Interface:

- (a) if all scheduled uses of transmission service fit within the adjusted total transfer capability, all are accepted (in other words, there is no Congestion);
- (b) if all scheduled uses of transmission service do not fit within the adjusted total transfer capability, scheduled uses of non-firm Existing Rights will be curtailed, pro rata, to the extent necessary. If the remaining scheduled uses of transmission service still do not fit within the adjusted total transfer capability, uses of conditional firm Existing Rights will be curtailed (based upon the levels of priority expressed in the contract usage templates for Schedules as described in Section 16.2.4.1.1) to the extent necessary;
- (c) if Congestion still exists after curtailing all lower priority schedules (e.g. requesting non-firm and conditional firm uses of transmission service under Existing Contracts), the remaining transmission capacity (that is not already reserved as firm Existing Rights) is priced based upon Adjustment Bids. To the extent there are insufficient Adjustment Bids to fully mitigate the remaining Congestion, the default Usage Charge will apply and the ISO will curtail ISO transmission service (in other words, new firm uses

other than Firm Transmission Rights uses evaluated in the Day-Ahead process), pro rata, to the extent necessary;

(d) If Congestion still exists after curtailing all new firm uses (other than Firm Transmission Rights uses) in the Day-Ahead scheduling process, scheduled uses of Firm Transmission Rights are then curtailed, pro rata, to the extent necessary; and

(e) if Congestion still exists after curtailing ISO new firm uses and uses of Firm Transmission Rights, scheduled uses of firm Existing Rights are then curtailed (based upon the priorities expressed in the contract usage templates associated with the Schedules as described in Section 16.2.4.1.1) to the extent necessary.

16.2.4.3 The Hour-Ahead Process.

16.2.4.3.1 Validation.

The ISO will coordinate the scheduling of the use of Existing Rights with new firm uses, in the Hour-Ahead process. The ISO will validate the submitted Schedules for conformity with the instructions provided by the Responsible PTOs. Invalid schedules will be rejected and the ISO will immediately communicate the results of each Scheduling Coordinator's validation to that Scheduling Coordinator via WEnet.

16.2.4.3.2 Scheduling Deadlines.

Those rights holders who must schedule the use of their rights by the deadline for the submission of Schedules in the Hour-Ahead Market must do so. After this time, the ISO will release these unused rights as available for new firm uses (not subject to recall).

16.2.4.3.3 Acceptance of Firm Transmission Schedules.

Before allocating any remaining transmission capacity under the following provisions of this Section 16.2, the ISO will accept Schedules associated with firm Existing Rights (subject to validation under 16.2.4.3.1), allocating transmission capacity for use by these rights holders.

16.2.4.3.4 Reservation of Firm Transmission Capacity.

The ISO will adjust the total transfer capabilities of Inter-Zonal Interfaces with respect to firm Existing Rights as it does in its Day-Ahead process described in this Section 16.2. Therefore, holders of Existing Rights are still able to exercise whatever scheduling flexibility they may have under their Existing Contracts after the Schedules and bids submittal deadline of the ISO's Hour-Ahead scheduling process, as described further in Section 16.2.4.4.

16.2.4.3.5 Allocation of Inter-Zonal Interface Capacities.

In the ISO's Congestion Management analysis of the Hour-Ahead Market, for each Inter-Zonal Interface:

- (a) if all scheduled uses of transmission service fit within the total transfer capability, all are accepted (in other words, there is no Congestion);
- (b) if all scheduled uses of transmission service do not fit within the total transfer capability, scheduled uses of non-firm Existing Rights will be curtailed, pro rata, to the extent necessary. If the remaining scheduled uses of transmission service still do not fit within the total transfer capability, scheduled uses of conditional firm Existing Rights will be curtailed (based upon the levels of priority expressed in the contract usage templates for the Schedules as described in Section 16.2.4.1.1) to the extent necessary;
- (c) if Congestion still exists after curtailing all lower priority schedules (e.g. representing non-firm and conditional firm uses of transmission service under Existing Contracts), the remaining transmission capacity (the subject of firm Existing Rights) is priced based upon Adjustment Bids. To the extent there are insufficient Adjustment Bids to fully mitigate the remaining Congestion, the default Usage Charge will apply and the ISO will curtail ISO transmission service (in other words, new firm uses including new firm uses of Firm Transmission Rights), pro rata, to the extent necessary; and
- (d) if Congestion still exists after curtailing ISO new firm uses, scheduled uses of firm Existing Rights will be curtailed (based upon the priorities expressed in the contract usage template associated with the Schedules as described in Section 16.2.4.1.1) to the extent necessary.

16.2.4.4 The ISO's Real-Time Process.

Consistent with Section 16.2.4.3.4, the ISO will honor those scheduling flexibilities that may be exercised by holders of Existing Rights through their respective Scheduling Coordinators during the ISO's real-time processes to the extent that such flexibilities do not interfere with or jeopardize the safe and reliable operation of the ISO Controlled Grid or Control Area operations. The real-time processes described in Sections 16.2.4.4.1 and 16.2.4.4.2 will occur during the three hours following the ISO's receipt of Preferred Hour-Ahead Schedules (that is, from two hours ahead of the start of the Settlement Period through the end of such Settlement Period).

16.2.4.4.1 Inter-Control Area Changes to Schedules that Rely on Existing Rights.

Changes to Schedules that occur during the ISO's real-time processes that involve changes to ISO Control Area imports or exports with other Control Areas (that is, inter-Control Area changes to Schedules) will be allowed and will be recorded by the ISO based upon notification received from the Scheduling Coordinator representing the holder of the Existing Rights. The ISO must be notified of any such changes to external import/export schedules. The ISO will receive notification of real-time changes to external import/export schedules, by telephone, from the Scheduling Coordinator representing the holder of the Existing Rights. The timing and content of any such notification must be consistent with the instructions previously submitted to the ISO by the Responsible PTO. The ISO will manually adjust the Scheduling Coordinator's schedule to conform with the other Control Area's net schedule in real time, and the notifying Scheduling Coordinator will be responsible for and manage any resulting Energy imbalance. These Imbalance Energy deviations will be priced and accounted to the Scheduling Coordinator representing the holder of Existing Rights in accordance with the Section 11.

16.2.4.4.2 Intra-Control Area Changes to Schedules that Rely on Existing Rights.

Changes to Schedules that occur during the ISO's real-time processes that do not involve changes to ISO Control Area imports or exports with other Control Areas (that is, intra-Control Area changes to Schedules) will be allowed and will give rise to Imbalance Energy deviations. These Imbalance Energy deviations will be priced and accounted to the Scheduling Coordinator representing the holder of Existing Rights in accordance with the Section 11.

17 [Not Used]

18 [Not Used]

19 DEMAND FORECASTS.

19.1 Scheduling Coordinator and Load-Serving Entity Demand Forecast Responsibilities.

19.1.1 Applicability to Scheduling Coordinators and Load-Serving Entities.

This Section 19.1 shall apply to each Scheduling Coordinator that must submit a Demand Forecast pursuant to Sections 4.5.3.7, 31.1.4.1 or the provisions of Section 40, and each Load-Serving Entity on whose behalf such Demand Forecasts are submitted.

19.1.2 Avoiding Duplication.

Each Scheduling Coordinator submitting a Demand Forecast to the ISO, and each Load-Serving Entity on whose behalf such Demand Forecast is submitted, shall ensure, to the best of their ability, that any Demand Forecast submitted to the ISO is not duplicated in another Scheduling Coordinator's Demand Forecast.

19.1.3 Required Performance.

Each Scheduling Coordinator submitting a Demand Forecast to the ISO, and each Load-Serving Entity on whose behalf such Demand Forecast is submitted, shall take all necessary actions to provide a Demand Forecast that reflects reasonable forecast accuracy standards. Scheduling Coordinators may develop and submit Demand Forecasts earlier than the timeline specified in Section 31.1.4.1 as appropriate to implement WECC-compliant weekend and holiday Demand Forecasts and scheduling practices.

[NOT USED]

[NOT USED]

19.2 ISO Responsibilities.

19.2.1 ISO Advisory Control Area Demand Forecasts.

The ISO will develop and publish on the ISO website and supply to the Scheduling Coordinators advisory Demand Forecasts comprised of Hourly Demand Forecasts for each Congestion Zone for each Settlement Period of the relevant Trading Day. The ISO will publish this information in accordance with the timing requirements set forth in this ISO Tariff.

19.2.2 ISO Annual Reports of Demand and Resources.

On an annual basis in accordance with the requirements of the WECC, the ISO will publish on its website reports that provide estimates of resource availability, peak Demand levels, and reserve capacity during anticipated peak Demand conditions for the ISO Control Area for the summer and any other specified seasons.

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 Sections 4.5.3.7 and 31.1.4.
- (g) 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:
 - (1) 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.
 - (2) Demand Forecast and other hourly data provided pursuant to Section 40.3.
 - (3) Information on existing import contracts, and any trades or sales of allocated import capacity, provided pursuant to Section 40.5.2.2.
 - (4) Information reported by non-Participating Generators pursuant to Sections 40.6A.3 and 40.7.3.
 - (5) Information submitted through the dispute or discrepancy resolution process pursuant to Section 40.2.3.

(h) The following information related to the Transmission Planning Process in accordance with Section 24 of Appendix EE:

- (1) Information received under Sections 24.2.3.2 and 24.2.3.3 of Appendix EE to the extent such information has been designated as confidential in accordance with the Business Practice Manual;
- (2) Information, the release of which may harm competitive markets, as determined by the CAISO's Department of Market Monitoring;
- (3) Information received by the CAISO pursuant to agreements and contracts, executed prior to December 21, 2007, that preclude the release of the information;
- (4) Information that involves proprietary analytical tools, computer codes, or any other material that is protected by intellectual property rights held by the CAISO, Project Sponsor, Market Participant or other third-party; and
- (5) Critical Energy Infrastructure Information.

However, composite documents, data, and other information that may be developed based on confidential information under this Section shall not be deemed confidential if the composite documents, data, and other information do not disclose any confidential information of any individual Scheduling Coordinator, Market Participant, or other third-party or Critical Energy Infrastructure Information.

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.
- (e) Notwithstanding the provisions of Section 20.2(f), information submitted through the Transmission Planning Process may be disclosed as follows:

- (i) Critical Energy Infrastructure Information may be provided to a requestor where such person is employed or designated by a Market Participant or electric utility regulatory agency within California to receive CEII, the requestor submits a statement as to the need for the CEII, and the requestor executes and returns to the CAISO the form of the non-disclosure agreement and non-disclosure statement included as part of the Business Practice Manual. The CAISO may, at its sole discretion, reject a request for CEII and upon such rejection, the requestor will be directed to utilize the FERC procedures for access to the requested CEII.
- (ii) Information that is confidential under Section 20.2(f)(i) or 20.2(f)(ii) may be disclosed to any individual designated by a Market Participant, electric utility regulatory agency within California, or other stakeholder that signs and returns to the CAISO the form of the non-disclosure agreement, nondisclosure statement and certification that the individual is or represents a non-Market Participant, which is any person or entity not involved in a marketing, sales, or brokering function as market, sales, or brokering are defined in FERC's Standards of Conduct for Transmission Providers (18 C.F.R. § 358 et seq.), included as part of the Business Practice Manual; and
- (iii) Data base and other transmission planning information obtained from the WECC, or its successor, may be disclosed to individuals designated by a Market Participant, electric utility regulatory agency within California, or other stakeholder in accordance with the procedures set forth in the Business Practice Manual.

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.

21.2 Application.

Notwithstanding any other provision in this Tariff, including the ISO Protocols, the temporary simplification measure specified in this Section 21 shall have effect until discontinued by a Notice of Full-Scale Operations issued by the Chief Executive Officer of the ISO.

21.3 Notices of Full-Scale Operations.

21.3.1 When the Chief Executive Officer of the ISO determines that the ISO is capable of implementing this ISO Tariff, including the ISO Protocols, without modification in accordance with a temporary simplification measure specified in this Section 21, he shall issue a notice ("Notice of Full-Scale Operations") and shall specify the relevant temporary simplification measure and the date on which it will permanently cease to apply, which date shall be not less than seven (7) days after the Notice of Full-Scale Operations is issued.

21.3.2 A Notice of Full-Scale Operations shall be issued when it is posted on the ISO Internet "Home Page," at <http://www.caiso.com> or such other Internet address as the ISO may publish from time to time.

22 MISCELLANEOUS.

22.1 Audits.

22.1.1 Materials Subject to Audit.

The ISO's financial books, cost statements, accounting records and all documentation pertaining to its operation as a state chartered independent institution which controls the operation of the ISO Controlled Grid to ensure open, non-discriminatory transmission access to all Market Participants and promotes the efficient use and reliable operation of the ISO Controlled Grid in accordance with this ISO Tariff, are subject to audit in the manner prescribed below:

22.1.2 ISO Audit Committee.

The ISO Governing Board shall have overall audit responsibility for the ISO. The ISO Audit Committee shall make recommendations to the ISO Governing Board in relation to the approval, initiation and

scheduling of the following audits:

22.1.2.1 Certified Financial Statement Audit.

Each year, an audit by an external independent certified public accounting firm shall be performed. This audit will be conducted in accordance with generally accepted auditing standards to verify that the ISO's financial statements are in compliance with generally accepted accounting principles and fairly present, in all material respects, the financial position, results of operation and cash flows for the audit period. The audit report will be addressed to the ISO Governing Board, copies will be provided to the ISO Audit Committee, and, upon request, to Market Participants.

22.1.2.2 Operations Audit.

Each year, an independent accounting firm shall review the ISO management's compliance with its operations policies and procedures. The ISO Audit Committee will appoint an independent firm to do this audit. This audit may also include material issues raised by Market Participants and approved by the ISO Audit Committee for inclusion in the audit scope. The audit report will be addressed to the ISO Governing Board, copies provided to the ISO Audit Committee, and upon request, to Market Participants.

22.1.2.3 Code of Conduct Audits.

On a periodic basis, but not less than once a year, an independent accounting firm shall conduct a management review of governors, officers, employees, substantially full-time consultants, or contractors of the ISO for compliance with the ISO Code of Conduct to ensure adherence to the highest standards of lawful and ethical conduct in their activities. The audit report shall be addressed to the ISO Audit Committee with copies provided to the ISO Governing Board and, upon request, to Market Participants.

22.1.2.4 Interim Audits.

At such other intervals agreed upon by a majority of the ISO Audit Committee members, audits may be undertaken for specific issues and concerns of Market Participants that the ISO Audit Committee believes, at its sole discretion, to be of significant and critical magnitude to the ISO. Such audits will be conducted by an independent accounting firm. The costs of such an audit will be borne by the requesting Market Participant(s), unless the ISO Audit Committee determines otherwise. Interim audits will be

conducted during normal business hours, after reasonable notice has been given to the ISO, and in accordance with the guidelines to be established by the ISO Audit Committee.

22.1.3 Audit Results.

Exceptions identified as a result of an audit will be reviewed with the ISO Audit Committee. The results of the audits and actions to be taken by the ISO as a result of the audit shall be mailed to Market Participants upon request.

22.1.4 Availability of Records.

The ISO will provide full and complete access to all financial books, cost statements, accounting records, and all documentation pertaining to the requirements of the specific audits being performed. Records relating to audits will be retained until the records retention requirements of the ISO are satisfied or until the audit issues are fully resolved, whichever is the later. The right of access to records does not require the creation of new records, reports, studies, or evaluations not already available.

22.1.5 Confidentiality of Information.

All proprietary information obtained through any audits will remain strictly confidential. All auditors shall sign a confidentiality agreement prior to being accepted as auditors by the ISO Audit Committee.

22.1.6 Payments.

Any payments agreed to between Market Participants and the ISO as a result of an audit, or directed by FERC, or disclosed by the ISO in reviews of its own books and records shall include interest computed at the rate calculated in accordance with the methodology specified for interest on refunds in FERC's regulations at 18 C.F.R § 35.19(a)(2)(iii) (as amended from time to time) from the due date to the date such adjustments are due.

22.2 Assignment.

Obligations and liabilities under this ISO Tariff and any Scheduling Coordinator Agreement or other agreements giving contractual effect to this ISO Tariff shall be binding on the successors and assigns of the parties to such agreements. No assignment of any Scheduling Coordinator Agreement or other

agreements giving contractual effect to this ISO Tariff shall relieve the original party from its obligations or liabilities to the ISO under this ISO Tariff or any such agreement arising or accruing due prior to the date of assignment.

22.3 Term and Termination.

22.3.1 This ISO Tariff, shall become effective on the date it is permitted to become effective by the FERC.

22.3.2 This ISO Tariff shall terminate upon approval of termination by the ISO Governing Board in accordance with the bylaws of the ISO and receipt of any necessary regulatory approval from FERC.

22.4 Notice.

22.4.1 Effectiveness.

Any notice, demand, or request in accordance with this ISO Tariff, unless otherwise provided in this ISO Tariff or in any ISO Protocol, shall be in writing and shall be deemed properly served, given, or made:

(a) upon delivery if delivered in person, (b) five (5) days after deposit in the mail if sent by first class United States mail, postage prepaid, (c) upon receipt of confirmation by return facsimile if sent by facsimile, or (d) upon delivery if delivered by prepaid commercial courier service.

22.4.2 Addresses.

Notices to the ISO shall be sent to such address as shall be notified by the ISO to Market Participants from time to time. Notices issued by the ISO to any Scheduling Coordinator shall be delivered to the address of the Scheduling Coordinator included in the Scheduling Coordinator Application Form. Notices to any Market Participant other than a Scheduling Coordinator shall be delivered by the ISO to the address given to it by the Market Participant. The ISO and any Market Participant may at any time change their address for notice by notifying the other party in writing.

22.4.3 Notice of Changes in Operating Rules and Protocols.

The ISO shall give all Market Participants notice of at least thirty (30) days of any changes or proposed changes in its operating rules, procedures and protocols, unless: (1) a different notice period is specified

by state or Federal law or (2) the change is reasonably required to address an emergency affecting the ISO Controlled Grid or its operations, in which case the ISO shall give Market Participants as much notice as is reasonably practicable. Any notices issued under this provision shall be delivered in accordance with the procedures set out in Section 22.4 of this ISO Tariff and, in the case of the ISO Protocols, Section 22.11 of this ISO Tariff.

22.5 Waiver.

Any waiver at any time by the ISO or any Market Participant of its rights with respect to any default under this ISO Tariff, or with respect to any other matter arising in connection with this ISO Tariff, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this ISO Tariff. Any delay short of the statutory period of limitations in asserting or enforcing any right shall not constitute or be deemed a waiver.

22.6 Staffing and Training To Meet Obligations.

The ISO shall engage sufficient staff to perform its obligations under this ISO Tariff in a satisfactory manner consistent with Good Utility Practice. The ISO shall make its own arrangements for the engagement of all staff and labor necessary to perform its obligations hereunder and for their payment. The ISO shall employ (or cause to be employed) only persons who are appropriately qualified, skilled and experienced in their respective trades or occupations. ISO employees and contractors shall abide by the ISO Code of Conduct for employees contained in the ISO bylaws and approved by FERC.

22.7 Accounts and Reports.

The ISO shall notify Market Participants of any significant change in the accounting treatment or methodology of any costs or any change in the accounting procedures, which is expected to result in a significant cost increase to any Market Participant. Such notice shall be given at the earliest possible time, but no later than, sixty (60) days before implementation of such change.

22.8 Applicable Law and Forum.

This ISO Tariff shall be governed by and construed in accordance with the laws of the State of California, except its conflict of laws provisions. Market Participants irrevocably consent that any legal action or

proceeding arising under or relating to this ISO Tariff to which the ISO ADR Procedures do not apply, shall be brought in any court of the State of California or any federal court of the United States of America located in the State of California. Market Participants irrevocably waive any objection that they may have now or in the future to said courts in the State of California as the proper and exclusive forum for any legal action or proceeding arising under or related to this ISO Tariff.

22.9 Consistency with Federal Laws and Regulations.

(a) Nothing in the Tariff shall compel any person or federal entity to: (1) violate federal statutes or regulations; or (2) in the case of a federal agency, to exceed its statutory authority, as defined by any applicable federal statutes, regulations, or orders lawfully promulgated thereunder. If any provision of this Tariff is inconsistent with any obligation imposed on any person or federal entity by federal law or regulation to that extent, it shall be inapplicable to that person or federal entity. No person or federal entity shall incur any liability by failing to comply with a Tariff provision that is inapplicable to it by reason of being inconsistent with any federal statutes, regulations, or orders lawfully promulgated thereunder; provided, however, that such person or federal entity shall use its best efforts to comply with the Tariff to the extent that applicable federal laws, regulations, and orders lawfully promulgated thereunder permit it to do so.

(b) If any provision of this Tariff requiring any person or federal entity to give an indemnity or impose a sanction on any person is unenforceable against a federal entity, the ISO shall submit to the Secretary of Energy or other appropriate Departmental Secretary a report of any circumstances that would, but for this provision, have rendered a federal entity liable to indemnify any person or incur a sanction and may request the Secretary of Energy or other appropriate Departmental Secretary to take such steps as are necessary to give effect to any provisions of this Tariff that are not enforceable against the federal entity.

(c) To the extent that the ISO suffers any loss as a result of being unable to enforce any indemnity as a result of such enforcement being in violation of federal laws or regulations to which it is entitled under the Tariff under this Section or otherwise, it shall be entitled to recover such loss through the Grid Management Charge.

22.10 ISO Grid Operations Committee; Changes To ISO Protocols.

22.10.1 ISO Grid Operations Committee.

The ISO Grid Operations Committee shall coordinate activities relating to the ISO Controlled Grid and shall consider suggestions for changes to the ISO Protocols in accordance with the procedures set out in Article IV, Section 4 of the ISO's bylaws.

22.11 ISO Protocol Amendment Process.

The ISO Governing Board shall establish an ISO Protocol amendment process in order to ensure that all affected parties have an opportunity to participate. Under that process, the ISO shall file for acceptance at the FERC any amendment to an ISO Protocol that is on file with the FERC.

22.13 Scheduling Responsibilities and Obligations.

Nothing in this ISO Tariff is intended to permit or require the violation of Federal or California law concerning hydro-generation and Dispatch, including but not limited to fish release requirements, minimum and maximum dam reservoir levels for flood control purposes, and in-stream flow levels. In carrying out its functions, the ISO will comply with and will have the necessary authority to give instructions to Participating TOs and Market Participants to enable it to comply with requirements of environmental legislation and environmental agencies having authority over the ISO in relation to Environmental Dispatch and will expect that submitted Schedules will support compliance with the requirements of environmental legislation and environmental agencies having authority over Generators in relation to Environmental Dispatch. In contracting for Ancillary Services and Imbalance Energy the ISO will not act as principal but as agent for and on behalf of the relevant Scheduling Coordinators.

ARTICLE II – TRANSMISSION SERVICE

23 CATEGORIES OF TRANSMISSION CAPACITY.

References to new firm uses shall mean any use of ISO transmission service, except for uses associated with Existing Rights. Prior to the start of the Day-Ahead scheduling process, for each Inter-Zonal Interface, the ISO will allocate the forecasted total transfer capability of the Interface to four categories.

This allocation will represent the ISO's best estimates at the time, and is not intended to affect any rights provided under Existing Contracts, except as provided in Section 16.2.4.3. The ISO's forecast of total transfer capability for each Inter-Zonal Interface will depend on prevailing conditions for the relevant Trading Day, including, but not limited to, the effects of parallel path (unscheduled) flows and/or other limiting operational conditions. This information will be posted on WEnet by the ISO in accordance with Appendix Y. In accordance with Section 16.2.4D of the ISO Tariff, the four categories are as follows:

- (a) transmission capacity that must be reserved for firm Existing Rights;
- (b) transmission capacity that may be allocated for use as ISO transmission service (i.e., "new firm uses");
- (c) transmission capacity that may be allocated by the ISO for conditional firm Existing Rights; and
- (d) transmission capacity that may remain for any other uses, such as non-firm Existing Rights for which the Responsible PTO has no discretion over whether or not to provide such non-firm service.

24 TRANSMISSION EXPANSION.

24.1 **[NOT USED]**

[NOT USED]

[NOT USED]

24.1.3 [NOT USED] LCRI Language Moved to Appendix EE

24.1.3.1 [NOT USED] LCRI Language Moved to Appendix EE

24.1.3.1 [NOT USED] LCRI Language Moved to Appendix EE

24.1.3.1 [NOT USED] LCRI Language Moved to Appendix EE

24.1.3.2 [NOT USED] LCRI Language Moved to Appendix EE

24.1.3.2 [NOT USED] LCRI Language Moved to Appendix EE

24.1.3.3 [NOT USED] LCRI Language Moved to Appendix EE

24.1.3.4 [NOT USED] LCRI Language Moved to Appendix EE

24.2

[NOT USED]

24.3 [NOT USED]

24.3 [NOT USED]

24.4 [NOT USED]

24.5 [NOT USED]

24.6 [NOT USED]

24.7 Cost Responsibility for Transmission Additions or Upgrades.

Cost responsibility for transmission additions or upgrades constructed pursuant to Section 24 of Appendix EE (including the responsibility for any costs incurred under Section 24.7 of Appendix EE) shall be determined as follows:

24.7.1 Where a Project Sponsor commits to pay the full cost of a transmission addition or upgrade as set forth in Section 24.1.1(a) of Appendix EE the full costs shall be borne by the Project Sponsor.

24.7.2 Where the need for a transmission addition or upgrade is determined by the ISO as set forth in Sections 24.1.1 (b)-(c), 24.1.2, and 24.1.4 of Appendix EE, the cost of the transmission addition or upgrade shall be borne by the Participating TO that will be the owner of the transmission addition or upgrade and shall be reflected in its Transmission Revenue Requirement.

24.7.3 Provided that the ISO has Operational Control of the transmission upgrade or addition, a Project Sponsor that does not recover the investment cost under a FERC-approved rate through the Access Charge or a reimbursement or direct payment from a Participating TO shall be entitled to receive:

- (a) its share, as determined in subsection (d) below, of the Wheeling revenues calculated in accordance with Section 26.1.4.3 that are attributable to the transmission addition or upgrade,

- which shall be determined by using the capacity increase, if any, of a Scheduling Point, to the extent such increase results from the addition or upgrade, as the rating increase for purposes of subsection (d) below;
- (b) its share, as determined in subsection (d) below, of the proceeds of the FTR auction for FTRs defined on the Inter-Zonal Interface of which the transmission addition or upgrade forms a part as set forth in Section 36.5.3, provided that the Project Sponsor does not receive FTRs from the ISO in accordance with Section 36.4.3 of the ISO Tariff; and
 - (c) its share, as determined in subsection (d) below, of the Congestion revenues provided as calculated pursuant to Section 27.1.2.1.6 on the Inter-Zonal Interface of which the transmission addition or upgrade forms a part.
 - (d) The Project Sponsor's share of Wheeling, Congestion and FTR auction revenues for the upgraded transmission facility shall be the number that is determined by dividing the number that is determined by subtracting the rating of the transmission facility before the upgrade or addition from the new rating for the upgraded or additional transmission facility by the new rating for the upgraded or additional transmission facility. The Participating TO's share of Wheeling, Congestion and FTR auction revenues for the upgraded or additional transmission facility shall be the number that is determined by subtracting the Project Sponsor's share from one hundred percent (100%). Such allocated shares shall become effective on the date the new rating takes effect. The full amount of capacity added to the system will be as determined through the regional reliability council process of the Western Electricity Coordinating Council or its successor.

24.7.4 Once a New Participating TO has executed the Transmission Control Agreement and it has become effective, the cost for New High Voltage Facilities for all Participating TOs shall be included in the ISO Grid-wide component of the High Voltage Access Charge in accordance with Schedule 3 of Appendix F, unless and with respect to Western Path 15 only, cost recovery is provided in Section 24.7.3. The Participating TO who is supporting the cost of the New High Voltage Facility shall include such costs in its High Voltage Transmission Revenue Requirement, regardless of which TAC Area the facility is

geographically located.

24.8 Ownership of and Charges for Expansion Facilities.

24.8.1 All transmission additions and upgrades constructed in accordance with this Section 24 shall form part of the ISO Controlled Grid and shall be operated and maintained by a Participating TO in accordance with the Transmission Control Agreement.

24.8.2 Each Participating TO that owns or operates transmission additions and upgrades constructed in accordance with this Section 24 shall provide access to them and charge for their use in accordance with this ISO Tariff and its TO Tariff.

24.9 Expansion by “Local Furnishing” Participating TOs

Notwithstanding any other provision of this ISO Tariff, a Local Furnishing Participating TO shall not be obligated to construct or expand facilities, (including interconnection facilities as described in Section 8 of the TO Tariff) unless the ISO or Project Sponsor has tendered an application under FPA Section 211 that requests FERC to issue an order directing the Local Furnishing TO to construct such facilities pursuant to Section 24 of the ISO Tariff. The Local Furnishing TO shall, within 10 days of receiving a copy of the Section 211 application, waive its right to a request for service under FPA Section 213(a) and to the issuance of a proposed order under FPA Section 212(c). Upon receipt of a final order from FERC that is no longer subject to rehearing or appeal, such Local Furnishing TO shall construct such facilities in accordance with this Section 24.

25 INTERCONNECTION OF GENERATING UNITS AND GENERATING FACILITIES TO THE ISO CONTROLLED GRID.

25.1 Applicability.

This Section 25 and the Standard Large Generator Interconnection Procedures (LGIP) set forth in ISO Tariff Appendix U, the Small Generator Interconnection Procedures (SGIP) set forth in ISO Tariff Appendix AA, or ISO Tariff Appendix W, as applicable, shall apply to:

- (a) each new Generating Unit that seeks to interconnect to the ISO Controlled Grid;
- (b) each existing Generating Unit connected to the ISO Controlled Grid that will be modified with a

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, SGIP, or ISO Tariff Appendix W, as applicable, which applicability shall be based on the maximum rated capacity of the new total capability of the power plant, including the capability of all of multiple energy production devices at a site, consistent with Section 4.10 of the SGIP.

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 a Standard Large Generator Interconnection Agreement in accordance with Section 11 of the LGIP, a Small Generator Interconnection Agreement in accordance with Section 3.3.4, 3.4.5, or 3.5.7 and Section 4.8 of the SGIP, 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 the LGIP, the LGIA, 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 3.4 of the SGIP, 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

determined in accordance with the principles set forth in this Section 26.1 and in Section 5 of the TO Tariff. The Access Charge shall comprise two components, which together shall be designed to recover each Participating TO's Transmission Revenue Requirement. The first component shall be the annual authorized revenue requirement associated with the transmission facilities and Entitlements turned over to the Operational Control of the ISO by a Participating TO approved by FERC. The second component shall be based on the Transmission Revenue Balancing Account (TRBA), which shall be designed to flow through to the Participating TO's Transmission Revenue Credits calculated in accordance with Section 5 of the TO Tariff and other credits identified in Sections 6 and 8 of Schedule 3 in Appendix F of the ISO Tariff.

Commencing on the transition date determined under Section 4 of Schedule 3 to Appendix F, the Access Charges shall be paid by any UDC or MSS Operator that is serving Gross Load in a PTO Service Territory, and shall consist, where applicable, of a High Voltage Access Charge, a Transition Charge and a Low Voltage Access Charge. High Voltage Access Charges and Low Voltage Access Charges shall each comprise two components, which together shall be designed to recover each Participating TO's High Voltage Transmission Revenue Requirement and Low Voltage Transmission Revenue Requirement, as applicable. The first component shall be based on the annual authorized Transmission Revenue Requirement associated with the high voltage or low voltage, as applicable, transmission facilities and Entitlements turned over to the ISO Operational Control by a Participating TO. The second component shall be the Transmission Revenue Balancing Account (TRBA), which shall be designed to flow through the Participating TO's Transmission Revenue Credits associated with the high voltage or low voltage, as applicable, transmission facilities and Entitlements and calculated in accordance with Section 5 of the TO Tariff and other credits identified in Sections 6, 8, and 13 of Schedule 3 of Appendix F of the ISO Tariff. Each Participating TO shall provide in its TO Tariff filing with FERC an appendix to such filing that states the Participating TO's High Voltage Transmission Revenue Requirement, its Low Voltage Transmission Revenue Requirement (if applicable) and its Gross Load used in developing the rate. The allocation of each Participating TO's Transmission Revenue Requirement between the High Voltage Transmission Revenue Requirement and the Low Voltage Transmission Revenue Requirement shall be undertaken in

accordance with Section 11 of Schedule 3 of Appendix F. To the extent necessary, each Participating TO shall make conforming changes to its TO Tariff.

The applicable High Voltage Access Charge and the Transition Charge shall be paid to the ISO by each UDC and MSS Operator based on its Gross Load connected to a High Voltage Transmission Facility in a PTO Service Territory, either directly or through intervening distribution facilities, but not through a Low Voltage Transmission Facility. The applicable High Voltage Access Charge, the Transition Charge and the Low Voltage Access Charge for the applicable Participating TO shall be paid by each UDC and MSS Operator based on its Gross Load in the PTO Service Territory. The applicable High Voltage Access Charge and Transition Charge shall be assessed by the ISO as a charge for transmission service under this ISO Tariff, shall be determined in accordance with Schedule 3 of Appendix F, and shall include all applicable components of the High Voltage Access Charge and Transition Charge set forth therein.

The Low Voltage Access Charge for each Participating TO is set forth in that Participating TO's TO Tariff. Each Participating TO shall charge for and collect the Low Voltage Access Charge, as provided in its TO Tariff, except that the ISO shall charge for and collect the Low Voltage Access Charge of each Non-Load-Serving Participating TO that qualifies under this Section 26.1 and Appendix F, Schedule 3, Section 13, unless otherwise agreed by the affected Participating TOs. If a Participating TO that is also a UDC, MSS Operator, or Scheduling Coordinator serving End-Use Customers is using the Low Voltage Transmission Facilities of another Participating TO, such Participating TO shall also be assessed the Low Voltage Access Charge of the other Participating TO by such other Participating TO, or by the ISO pursuant to Section 13 of Schedule 3 of Appendix F. The ISO shall provide to the applicable Participating TO a statement of the amount of Energy delivered to each UDC and MSS Operator serving Gross Load that utilizes the Low Voltage Transmission Facilities of that Participating TO on a monthly basis. If a UDC or MSS Operator that is serving Gross Load in a PTO Service Territory has Existing Rights to use another Participating TO's Low Voltage Transmission Facilities, such entity shall not be charged the Low Voltage Access Charge for delivery of Energy to Gross Load for deliveries using the Existing Rights. Each Participating TO shall recover Standby Transmission Revenues directly from the Standby Service Customers of that Participating TO through its applicable retail rates.

Where a Non-Load-Serving Participating TO has Low Voltage Transmission Facilities, the ISO shall assess the Low Voltage Access Charge for each project of that Non-Load-Serving Participating TO to the UDC or MSS Operator of each Participating TO that is directly connected to one or more Low Voltage Transmission Facilities of that project, unless otherwise agreed by the affected Participating TOs. The Non-Load-Serving Participating TO shall calculate separately its Low Voltage Transmission Revenue Requirement for each individual transmission project that includes one or more Low Voltage Transmission Facilities. If the Non-Load-Serving Participating TO's Low Voltage Transmission Facilities projects are directly connected to the facilities of the same Participating TO(s), the Low Voltage Access Charge shall be calculated for the group of Low Voltage Transmission Facilities. A separate Low Voltage Access Charge shall apply based on the Low Voltage Transmission Revenue Requirement for the relevant project or projects of such Non-Load-Serving Participating TO divided by the Gross Load of all UDCs or MSS Operators of a Participating TO that are directly connected to the relevant Low Voltage Transmission Facility or group of facilities.

A Non-Load-Serving Participating TO must include any over- or under-recovery of its annual Low Voltage Transmission Revenue Requirement for the relevant project or group of projects in its low voltage TRBA adjustment for its Low Voltage Access Charge for the relevant project or group of projects pursuant to Section 13.1 of Schedule 3 of Appendix F.

A Participating TO that is a UDC or MSS Operator to whom the Low Voltage Access Charge of a Non-Load-Serving Participating TO is assessed shall include these billed Low Voltage Access Charge amounts in its low voltage TRBA adjustment for its Low Voltage Access Charge, together with all other applicable low voltage TRBA adjustments.

26.1.1 Publicly Owned Electric Utilities Access Charge.

Local Publicly Owned Electric Utilities whose transmission facilities are under ISO Operational Control shall file with the FERC their proposed High Voltage Transmission Revenue Requirements, and any proposed changes thereto, under procedures determined by the FERC to be applicable to such filings and shall give notice to the ISO and to all Scheduling Coordinators of any such filing. A prospective New

Participating TO that is a Local Publicly Owned Electric Utility shall submit its first proposed High Voltage Transmission Revenue Requirement to the FERC and the ISO at the time the Local Publicly Owned Electric Utility submits its application to become a New Participating TO in accordance with the Transmission Control Agreement. Federal power marketing agencies whose transmission facilities are under ISO Operational Control shall develop their High Voltage Transmission Revenue Requirement pursuant to applicable federal laws and regulations.

The procedures for public participation in a federal power marketing agency's ratemaking process are posted on the federal power marketing agency's website. Each federal power marketing agency shall

also post on its website the Federal Register Notices and FERC orders for rate making processes that impact the federal power marketing agency's High Voltage Transmission Revenue Requirement. At the time the federal power marketing agency submits its application to become a New Participating TO in accordance with the Transmission Control Agreement, it shall submit its first proposed High Voltage Transmission Revenue Requirement to the FERC and the ISO.

26.1.2 High Voltage Access Charge and Transition Charge Settlement.

UDCs and MSS Operators serving Gross Load in a PTO Service Territory shall be charged on a monthly basis, in arrears, the applicable High Voltage Access Charge and Transition Charge. The High Voltage Access Charge and Transition Charge for a billing period is calculated by the ISO as the product of the applicable High Voltage Access Charge or Transition Charge, as applicable, and Gross Load connected to the facilities of the UDC and MSS Operator in the PTO Service Territory. The High Voltage Access Charge and Transition Charge are determined in accordance with Schedule 3 of Appendix F of the ISO Tariff. These rates may be adjusted from time to time in accordance with Schedule 3 to Appendix F. During the 10-year transition period described in Section 4 of Schedule 3 of Appendix F of the ISO Tariff, a UDC or MSS Operator that is also a Participating TO shall pay, or receive payment of, if applicable, the difference between (i) the High Voltage Access Charge and the Transition Charge applicable to its transactions as a UDC or MSS Operator; and (ii) the disbursement of High Voltage Access Charge revenues to which it is entitled pursuant to Section 26.1.3.

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

The ISO shall collect and pay, on a monthly basis, to Participating TOs all High Voltage Access Charge and Transition Charge revenues at the same time as other ISO charges and payments are settled. High Voltage Access Charge revenues received with respect to the High Voltage Access Charge and the Transition Charge shall be distributed to Participating TOs in accordance with Appendix F, Schedule 3, Section 10.

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.

26.1.4.4 Information Required from Scheduling Coordinators.

Scheduling Coordinators that schedule Wheeling Out or Wheeling Through transactions to a Bulk Supply Point, or other point of interconnection between the ISO Controlled Grid and the transmission system of a Non-Participating TO, that are located within the ISO Control Area, shall provide the ISO, within 5 days from the end of the calendar month to which the relevant Trading Day relates, details of such transactions scheduled by them (other than transactions scheduled pursuant to Existing Contracts) sorted by Bulk Supply Point or point of interconnection for each Settlement Period (including kWh scheduled). The ISO shall use such information, which may be subject to review by the ISO, to settle Wheeling Access Charges and payments. The ISO shall publish a list of the Bulk Supply Points or interconnection points to which this Section 26.1.4.4 applies together with details of the electronic form and procedure to be used by Scheduling Coordinators to submit the required information on the ISO "Home Page".

26.1.5 Unbundled Retail Transmission Rates.

The Access Charge for unbundled retail transmission service provided to End-Users by a FERC-jurisdictional electric utility Participating TO shall be determined by the FERC and submitted to the ISO for information only. For a Local Publicly Owned Electric Utility, retail transmission service rates shall be determined by the Local Regulatory Authority and submitted to the ISO for information only.

26.2 Tracking Account.

If the Access Charge rate methodology implemented pursuant to Section 26.1 results in Access Charge rates for any Participating TO which are different from those in effect prior to the ISO Operations Date, an amount equal to the difference between the new rates and the prior rates for the remainder of the period, if any, during which a cost recovery plan established pursuant to Section 368 of the California Public Utilities Code (as added by AB 1890) is in effect for such Participating TO shall be recorded in a tracking account. The balance of that tracking account will be recovered from customers and paid to the appropriate Participating TO after termination of the cost recovery plan set forth in Section 368 of California Public Utilities Code (as added by AB 1890). The recovery and payments shall be based on an amortization period not exceeding three years in the case of electric corporations regulated by the CPUC or five years for Local Publicly Owned Electric Utilities.

26.3 Addition of New Facilities After ISO Implementation.

The costs of transmission facilities placed in service after the ISO Operations Date shall be recovered consistent with the cost recovery determinations made pursuant to Section 24.7.

26.4 Effect on Tax-Exempt Status.

Nothing in this Section shall compel any Participating TO to violate any restrictions applicable to facilities financed with tax-exempt bonds or contractual restrictions and covenants regarding the use of transmission facilities.

26.5 Transition Mechanism.

During the ten-year transition period described in Section 4 of Schedule 3 to Appendix F, the Original Participating TOs collectively shall pay to the ISO each year an amount equal to, annually, for all New Participating TOs, the amount, if any, by which the New Participating TO's cost of Existing High Voltage Facilities associated with Gross Loads in the PTO Service Territory of the New Participating TO is increased by the implementation of the High Voltage Access Charge described in Schedule 3 to Appendix F. Responsibility for such payments shall be allocated to Original Participating TOs in accordance with Schedule 3 to Appendix F. Amounts payable by Original Participating TOs under this section shall be recoverable as part of the Transition Charge calculated in accordance with Schedule 3 of Appendix F. Amounts received by the ISO under this section shall be disbursed to New Participating TOs with Existing High Voltage Facilities based on the ratio of each New Participating TO's net increase in costs in the categories described in the first sentence of this section, to the sum of the net increases in such costs for all New Participating TOs with Existing High Voltage Facilities.

26.6

The costs of an LCRIF shall be includable in a Participating TO's High Voltage Revenue Requirement. Any Participating TO that owns an LCRIF shall set forth in its TO Tariff a charge payable by LCRIGs connected to that facility. The charge shall require each LCRIG to pay on a going forward basis its pro rata share of the Transmission Revenue Requirement associated with the LCRIF which shall be calculated based on the maximum capacity of the LCRIG relative to the capacity of the LCRIF. Each Participating TO shall credit its High Voltage TRR with revenues received from LCRIGs with respect to such charges either by recording such revenues in its TRBA or through another mechanism approved by FERC.

26.6.1 Location Constrained Resource Interconnection Facilities that Become Network Facilities.

If the construction of a new transmission facility or upgrade causes an LCRIF to become a network facility, then, effective on the in-service date of such new transmission facility or upgrade, the LCRIGs connected to the LCRIF shall not be required to pay charges described in Section 26.6. The LCRIGs shall remain responsible for charges due prior to that date.

ARTICLE III – MARKET OPERATIONS

27 OVERVIEW OF MARKETS.

27.1 Congestion Management.

27.1.1 Zonal Congestion Management.

27.1.1.1 The ISO Will Perform Congestion Management.

27.1.1.1.1 Transmission Congestion.

Congestion occurs when there is insufficient transfer capacity to simultaneously implement all of the Preferred Schedules that Scheduling Coordinators submit to the ISO.

27.1.1.1.1.1 Transmission Capacity Reserved under Existing Contracts will not be Subject to the ISO's Congestion Management Procedures.

27.1.1.1.2 Zone-Based Approach.

The ISO will use a Zone-based approach to manage Congestion. A Zone is a portion of the ISO Controlled Grid within which Congestion is expected to occur infrequently or have relatively low Congestion Management costs. Inter-Zonal Interfaces consist of transmission facilities that are expected to have relatively high Congestion Management costs. For these interfaces, allocation of usage based on the value placed on these interfaces by the Scheduling Coordinators will increase efficient use of the ISO Controlled Grid.

27.1.1.1.3 Types of Congestion.

Congestion that occurs on Inter-Zonal Interfaces is referred to as "Inter-Zonal Congestion." Congestion that occurs due to transmission system Constraints within a Zone is referred to as "Intra-Zonal Congestion." Inter-Zonal Congestion Management will ignore Intra-Zonal Congestion. Intra-Zonal Congestion will be managed in accordance with Tariff Section 27.1.1.6.

27.1.1.1.4 Elimination of Potential Transmission Congestion.

The ISO's Day-Ahead and Hour-Ahead scheduling procedures will eliminate potential Inter-Zonal

Congestion by:

27.1.1.1.4.1 scheduling the use of Inter-Zonal Interfaces by the Scheduling Coordinators who place the highest value on those rights, based on the Adjustment Bids that are submitted by Scheduling Coordinators; and

27.1.1.1.4.2 rescheduling Scheduling Coordinators' resources (but so that Intra-Zonal transmission limits are not violated) using the Adjustment Bids that are submitted by Scheduling Coordinators.

27.1.1.1.5 Elimination of Real-Time Inter-Zonal Congestion.

In its management of Inter-Zonal Congestion in real time, the ISO will issue Dispatch Instructions as necessary to relieve Inter-Zonal Congestion by Dispatching Generation or Demand, as necessary, based on the Energy Bids in accordance with Section 34.3.2. The ISO will use the RTD Software to alleviate Inter-Zonal Congestion as described in Section 34.3.2.

27.1.1.2 General Requirements for the ISO's Congestion Management.

The ISO's Congestion Management in the Day-Ahead Market and Hour-Ahead Market shall:

27.1.1.2.1 only operate if the Scheduling Coordinators do not eliminate Congestion voluntarily;

27.1.1.2.2 adjust the Schedules submitted by Scheduling Coordinators only as necessary to alleviate Congestion;

27.1.1.2.3 maintain separation between the resource portfolios of different Scheduling Coordinators, by not arranging any trades between Scheduling Coordinators as part of the Inter-Zonal Congestion Management process;

27.1.1.2.4 for Inter-Zonal Congestion Management, suggest, but not require, rescheduling within Scheduling Coordinators' portfolios of Schedules to produce a feasible Schedule by the conclusion of the scheduling procedure;

27.1.1.2.5 publish information and, if requested by Scheduling Coordinators will provide a mechanism to facilitate voluntary trades among Scheduling Coordinators;

27.1.1.2.6 adjust the Schedules submitted by Scheduling Coordinators on the basis of any price information voluntarily submitted through their Adjustment Bids; and

27.1.1.2.7 for the hours when the ISO applies its Inter-Zonal Congestion Management apply the same Usage Charge to all Scheduling Coordinators for their allocated share of the Inter-Zonal Interface capacity.

27.1.1.3 Use of Computational Algorithms for Congestion Management and Pricing.

The ISO will use computer optimization algorithms to implement its Congestion Management process.

27.1.1.4 Adjustment Bids Will Be Used by the ISO to Manage Congestion.

27.1.1.4.1 Uses of Adjustment Bids by the ISO.

27.1.1.4.1.1 The ISO shall use the Adjustment Bids, in both the Day-Ahead Market and the Hour-Ahead Market, to schedule Inter-Zonal Interface capacity to those Scheduling Coordinators which value it the most to reflect the Scheduling Coordinators' implicit values for Inter-Zonal Interface capacity and to determine the prices for the use of Congested Inter-Zonal Interfaces.

27.1.1.4.1.2 The Adjustment Bids will be used by the ISO to determine the marginal value associated with each Congested Inter-Zonal Interface.

27.1.1.4.1.3 The ISO shall use Energy Bids from Generating Units and from other resources in the ISO's real-time system operation, for increasing resources' output for Intra-Zonal Congestion Management and to decrement Generation in order to accommodate Overgeneration conditions, including Reliability Must-Run Generation which the ISO requests under Reliability Must-Run Contracts.

27.1.1.4.1.4 To facilitate trades amongst Scheduling Coordinators, the ISO will develop procedures to publish Adjustment Bids of those Scheduling Coordinators who authorize the publication of their identity and/or Adjustment Bids. Scheduling Coordinators will then be able to utilize this information to conduct trades to aid Congestion Management.

27.1.1.4.2 Submission of Adjustment Bids.

27.1.1.4.2.1 Each Scheduling Coordinator is required to submit a preferred operating point for each of

its resources. However, a Scheduling Coordinator is not required to submit an Adjustment Bid for a resource.

27.1.1.4.2.2 The minimum MW output level specified for a resource, which may be zero MW, and the maximum MW output level specified for a resource must be physically realizable by the resource.

27.1.1.4.2.3 The Scheduling Coordinator's preferred operating point for each resource must be within the range of the Adjustment Bids.

27.1.1.4.2.4 Adjustment Bids can be revised by Scheduling Coordinators after the Day-Ahead Market has closed for consideration in the Hour-Ahead Market and, after the Hour-Ahead Market has closed, for consideration in the Real Time Market provided that, if the ISO has accepted all, or a portion of, an offered Adjustment Bid, the Scheduling Coordinator is obligated to provide the relevant capacity increase or decrease to the ISO at the price of the accepted Adjustment Bid.

27.1.1.4.2.5 During the ISO's Day-Ahead scheduling process, the MW range of the Adjustment Bid, but not the price values, may be changed.

27.1.1.4.2.6 The Adjustment Bids that the Scheduling Coordinators submit constitute implicit bids for transmission between Zones on either side of a Congested Inter-Zonal Interface. An Adjustment Bid shall constitute a standing offer to the ISO until it is withdrawn.

27.1.1.4.2.7 The ISO may impose additional restrictions and bidding activity rules on the form of Adjustment Bids, the updating of Adjustment Bids, and the Scheduling Coordinator that may submit Adjustment Bids in connection with inter-Scheduling Coordinator trades, as needed, to ensure that the ISO's computational algorithms can operate reliably and produce efficient outcomes.

27.1.1.5 Inter-Zonal Congestion Management.

27.1.1.5.0 Inter-Zonal Congestion Management will use a DC optimal power flow (OPF) program that uses linear optimization techniques with active power (MW) controls only.

27.1.1.5.0.1 Inter-Zonal Congestion Management will involve adjusting Schedules to remove potential violations of Inter-Zonal Interface Constraints, minimizing the Redispatch cost, as determined by the

submitted Adjustment Bids that accompany the submitted Schedules.

27.1.1.5.1 The scheduling procedures in the Day-Ahead Market and Hour-Ahead Market will first ascertain, through power flow calculations, whether or not Inter-Zonal Congestion would exist if all of the Preferred and Revised Schedules submitted by the Scheduling Coordinators were accepted by the ISO. If no Inter-Zonal Congestion would exist, then all Inter-Zonal Interface uses will be accepted and the Usage Charges will be zero.

27.1.1.5.2 The purpose of Inter-Zonal Congestion Management is to allocate the use of, and determine the marginal value of, active Inter-Zonal Interfaces. The ISO's Inter-Zonal Congestion Management process will allocate Congested transmission to those users who value it the most and will charge all Scheduling Coordinators for their allocated usage of Congested Inter-Zonal Interfaces on a comparable basis. All Scheduling Coordinators within a Zone will see the same price for transmitting Energy across a Congested Inter-Zonal Interface, irrespective of the particular locations of their Generators, Demands and external imports/exports. Inter-Zonal Congestion Management will comply with the requirements stated in Sections 27.1.1.2, 27.1.1.4 and 27.1.1.5.

27.1.1.5.2.1 Inter-Zonal Congestion Management will keep each Scheduling Coordinator's portfolio of Generation and Demand (i.e., the Scheduling Coordinator's Preferred Schedule) separate from the portfolios of the other Scheduling Coordinators, as the ISO adjusts the Schedules to alleviate Inter-Zonal Congestion. Inter-Zonal Congestion Management will not involve arranging or modifying trades between Scheduling Coordinators. Each Scheduling Coordinator's portfolio will be kept in balance (i.e., its Generation plus external imports, as adjusted for Transmission Losses, and Inter-Scheduling Coordinator Energy Trades (whether purchases or sales) will still match its Demand plus external exports) after the adjustments. Market Participants will have the opportunity to trade with one another and to revise their Schedules during the first Congestion Management iteration in the Day-Ahead Market, and between the Day-Ahead Market and Hour-Ahead Market. Inter-Zonal Congestion Management will also not involve the optimization of Scheduling Coordinator portfolios within Zones (where such apparently non-optimal Schedules are submitted by Scheduling Coordinators). Adjustments to individual Scheduling Coordinator portfolios within a Zone will be either incremental (i.e., an increase in Generation and external imports

and a decrease in Demand and external exports) or decremental (i.e., a decrease in Generation and external imports and an increase in Demand and external exports), but not both.

27.1.1.5.2.2 If Congestion would exist on one or more active Inter-Zonal Interfaces, then the ISO shall execute its Inter-Zonal Congestion Management algorithms to determine a set of tentative (in the Day-Ahead procedure) allocations of Inter-Zonal Interface rights and tentative (in the Day-Ahead procedure) Usage Charges, where the Usage Charges will be calculated as the marginal values of the Congested Inter-Zonal Interfaces. The marginal value of a Congested Inter-Zonal Interface is calculated by the ISO's computer optimization algorithm to equal the total change in Redispatch costs (based on the Adjustment Bids) that would result if the interface's scheduling limit was increased by a small increment.

27.1.1.5.2.3 As part of the Day-Ahead scheduling procedure, but not the Hour-Ahead scheduling procedure, Scheduling Coordinators will be given the opportunity to adjust their Preferred Schedules (including the opportunity to make trades amongst one another) and to submit Revised Schedules to the ISO, in response to the ISO's Suggested Adjusted Schedules and prices for Inter-Zonal Interfaces.

27.1.1.5.2.4 If the ISO receives any Revised Schedules it will execute its Inter-Zonal Congestion Management algorithms using revised Preferred Schedules, to produce a new set of allocations and prices.

27.1.1.5.2.5 All of the ISO's calculations will treat each Settlement Period independently of the other Settlement Periods in the Trading Day.

27.1.1.5.2.6 If inadequate Adjustment Bids have been submitted to schedule Inter-Zonal Interface capacity on an economic basis and to the extent that scheduling decisions cannot be made on the basis of economic value, the ISO will allocate the available Inter-Zonal Interface capacity to Scheduling Coordinators in proportion to their respective proposed use of that capacity as indicated in their Schedules and shall curtail scheduled Generation and Demand to the extent necessary to ensure that each Scheduling Coordinator's Schedule remains balanced, except for those uses of transmission service under Existing Contracts, which are curtailed in accordance with Sections 16.2.4.2 and 16.2.4.3.

27.1.1.5.2.7 The ISO will publish information prior to the Day-Ahead Market, between the iterations of

the Day-Ahead Market, and prior to the Hour-Ahead Market, to assist the Scheduling Coordinators to construct their Adjustment Bids so as to actively participate in the management of Congestion and the valuation of Inter-Zonal Interfaces. This information may include the ISO's most-current information regarding: potentially Congested paths, projected transmission uses, projected hourly Loop Flows across Inter-Zonal Interfaces, scheduled line Outages, forecasts of expected system-wide Load, the ISO's Ancillary Services requirements, Generation Meter Multipliers, and power flow outputs.

27.1.1.5.2.8 The ISO will also publish information, once it is available, regarding tentative prices for the use of Inter-Zonal Interfaces, and Generation shift factors for the use of Inter-Zonal Interfaces, which indicate the relative effectiveness of Generation shifts in alleviating Congestion.

27.1.1.6 Intra-Zonal Congestion Management.

(a) In the hour prior to the beginning of the Settlement Period the ISO may adjust Scheduling Coordinators' Final Schedules to alleviate Intra-Zonal Congestion. Except in those instances where the ISO calls Reliability Must-Run Units as provided in Section 30.6.1 of the ISO Tariff, the ISO will adjust resources in accordance with subsections (b) and (c) of this Section 27.1.1.6.

(b) Except as provided in Section 30.6.1 of the ISO Tariff, in the event of Intra-Zonal Congestion, the ISO shall adjust Generating Units and Curtailable Demands (or Interconnection schedules of System Resources in the Control Areas) to alleviate the Constraints as described in subsection (d) below.

(c) Additional Congestion Relief. In the event that there are insufficient resources which provide financial bids to mitigate Inter-Zonal and Intra-Zonal Congestion, Final Schedules which do not rely on Existing Contracts will be adjusted in real time by allocating transmission capacity on a pro rata basis. Final Schedules which rely on Existing Contracts will be adjusted in real time by allocating transmission capacity in accordance with the operating instructions submitted under Section 16.2.4. With respect to facilities financed with Local Furnishing Bonds the ISO shall adjust Final Schedules in real time in a fashion consistent with Sections 3 and 26.4 of the ISO Tariff, Appendix B of the TCA, and Operating Procedures governing the use of such facilities.

(d) Any Generating Unit dispatched to manage Intra-Zonal Congestion shall: (1) if dispatched to

increase its output, be paid the greater of its bid price (or mitigated bid if applicable) or the relevant Market Clearing Price; (2) if dispatched to decrease its output, be charged the lesser of its decremental reference price of the relevant Market Clearing Price. The ISO shall not re-dispatch MSS resources to manage Intra-Zonal congestion as set forth in this Section 27.1.1.6, as provided for in the MSS Agreement. The ISO shall treat hydroelectric resources the same as MSS resources for purposes of managing Intra-Zonal congestion under this Section 27.1.1.6.

27.1.1.6.1 Decremental Bids.

With regard to decremental bids, if Final Hour-Ahead Schedules cause Congestion on the Intra-Zonal interface, the ISO shall, after Dispatching available and effective Reliability Must-Run Units to manage the Congestion, apply the decremental reference prices determined by the independent entity that determines the reference prices for the Automatic Mitigation Procedure (AMP) as described in Appendix P, Attachment A. The ISO shall Dispatch Generating Units according to the decremental reference prices thus established, the resource's effectiveness on the Congestion, and other relevant factors such as Energy limitations, existing contractual restrictions, and Regulatory Must-Run or Regulatory Must-Take status, to alleviate the Congestion after Final Hour-Ahead Schedules are issued. Where the ISO must reduce a Generating Unit's output, the ISO shall Dispatch Generating Units according to the decremental reference prices and not according to Adjustment Bids or Supplemental Energy Bids to alleviate Intra-Zonal Congestion. No Generating Unit shall be Dispatched below its minimum operating level or above its maximum operating level. No Reliability Must-Run Unit shall be Dispatched below the operating level determined by the ISO as necessary to maintain reliability. If Congestion still exists after all Generating Units are Dispatched to their minimum operating levels, the ISO shall instruct Generating Units to shut off in merit order based on their total shut-down costs, beginning with the most expensive unit, where such shut-down costs include the lesser of the cost to start up the Generating Unit or to keep the Generating Unit warm for each Generating Unit with a non-zero Final Day-Ahead Schedule for Energy for the next day. Units shut off due to Congestion as set forth in this Section 27.1.1.6.1 shall be charged the lesser of the decremental reference price for the operating range between zero MW output and the unit's minimum operating level or the relevant Market Clearing Price.

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 non-positive bids, 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

5. If sufficient data do not exist to calculate a reference level on the basis of the first, second, or fourth methods and the third method is not applicable or an attempt to determine a reference level in consultation with a Market Participant has not been successful, the independent entity responsible for determining reference prices shall determine a reference level on the basis of:

i. the independent entity's estimated costs of an electric facility, taking into account available operating costs data, opportunity cost, and appropriate input from the Market Participant, and the best information available to the independent entity; or

ii. an appropriate average of competitive bids of one or more similar electric Facilities.

(b) Monotonicity. The decremental bid reference levels (\$/MWh bid price) for the different bid segments of each resource shall be made monotonically non-decreasing by the independent entity responsible for determining reference prices by proceeding from the highest MW bid segment moving through each lower MW bid segment. The reference level of each succeeding bid segment, moving from right to left in order of decreasing operating level, shall be the lower of the reference level of the preceding bid segment or the reference level determined according to paragraph (a) above.

27.1.1.6.2 Incremental Bids.

With regard to incremental bids, except as provided in Sections 30.6, 27.1.1.6.1 and 11.2.4.2, the ISO will perform Intra-Zonal Congestion Management in real time using available Imbalance Energy bids, based on their effectiveness and in merit order, to minimize the cost of alleviating Congestion. In the event no Imbalance Energy bids are available, the ISO will exercise its authority to direct the Redispatch of resources as allowed under the Tariff, including Section 16.2.

27.1.1.6.3 Cost of Intra-Zonal Congestion Management.

The net of the amounts paid by the ISO to the Scheduling Coordinators and the amounts charged to the Scheduling Coordinators will be calculated and charged to all Scheduling Coordinators through a Grid Operations Charge, as described in Section 27.1.3.

27.1.1.6.4 [Deletion pending FERC approval]

27.1.1.7 Creation, Modification and Elimination of Zones.

27.1.1.7.1 Active Zones.

The Active Zones are as set forth in Appendix I to this ISO Tariff.

27.1.1.7.2 Modifying Zones.

The ISO shall monitor usage of the ISO Controlled Grid to determine whether new Zones should be created, or whether existing Zones should be eliminated, in accordance with the following procedures.

27.1.1.7.2.1 If over a 12-month period, the ISO finds that within a Zone the cost to alleviate the Congestion on a path is equivalent to at least 5 percent of the product of the rated capacity of the path and the weighted average High Voltage Access Charge and Low Voltage Access Charge, as applicable, of the Participating TOs, the ISO may announce its intention to create a new Zone. In making this calculation, the ISO will only consider periods of normal operations. A new Zone will become effective 90 days after the ISO Governing Board has determined that a new Zone is necessary.

27.1.1.7.2.2 The ISO may, at its own discretion, shorten the 12-month and 90-day periods for creating new Zones if the ISO Governing Board determines that the planned addition of new Generation or Load would result in Congestion that would meet the criterion specified in Section 27.1.1.7.2.1.

27.1.1.7.2.3 If a new transmission project or other factors will eliminate Congestion between existing Zones, the ISO may modify or eliminate those Zones at its discretion.

27.1.1.7.2.4 The ISO may change the criteria for establishing or modifying Zone boundaries, subject to regulatory approval by the FERC.

27.1.1.7.3 Active and Inactive Zones.

27.1.1.7.3.1 An Active Zone is one for which a workably-competitive Generation market exists on both sides of the relevant Inter-Zonal Interface for a substantial portion of the year so that Congestion Management can be effectively used to manage Congestion on the relevant Inter-Zonal Interface.

Pending the ISO's determination of the criteria for defining "workable competitive generation markets", the Inactive Zones will, as an interim measure, be those specified in Section 27.1.1.7.3.3.

27.1.1.7.3.2 The Congestion Management described in this Section 27.1.1, and the Usage Charges stemming from the application of these procedures, shall not apply to Inter-Zonal Interfaces with Inactive Zones.

27.1.1.7.3.3 The initial inactive Inter-Zonal Interfaces are the interface between the San Francisco Zone and the remainder of the ISO Controlled Grid, and the interface between the Humboldt Zone and the remainder of the ISO Controlled Grid. The initial Inactive Zones are the San Francisco Zone and the Humboldt Zone.

27.1.1.7.3.4 The determination of whether a new Zone or an existing Inactive Zone should become an Active Zone and the determination of whether a workably-competitive Generation market exists for a substantial portion of the year, shall be made by the ISO Governing Board, using the same approval criteria as are used for the creation or modification of Zones. The ISO Governing Board shall adopt criteria that defines a "workably competitive Generation" market. The ISO Governing Board will review the methodology used for the creation or modification of Zones (including Active Zones and Inactive Zones) on an annual basis and make such changes as it considers appropriate.

27.1.2 Usage Charges and Grid Operations Charges.

27.1.2.0.1 The ISO will collect Usage Charges from Scheduling Coordinators for their Scheduled use of Congested Inter-Zonal Interfaces. If Adjustment Bids are exhausted and Schedules are adjusted pro rata, the ISO will apply a default Usage Charge calculated in accordance with Section 27.1.2.1.3.1

27.1.2.1 Usage Charges for Inter-Zonal Congestion.

The Usage Charge is used by the ISO to charge Scheduling Coordinators for the use of Congested Inter-Zonal Interfaces. Subject to Section 16.2.3.4.1, the Usage Charge shall be paid by all Scheduling Coordinators that use a Congested Inter-Zonal Interface. If a Scheduling Coordinator uses more than one Congested Inter-Zonal Interface, it will pay a Usage Charge for each Congested Inter-Zonal Interface that it uses.

27.1.2.1.1 Calculation and Allocation of Usage Charge.

Those Scheduling Coordinators who are permitted by the ISO to use a Congested Inter-Zonal Interface will pay a Usage Charge. The Usage Charge is determined using Inter-Zonal Congestion Management described in Section 27.1.1.5, and is calculated as the hourly marginal value of an incremental kW of Inter-Zonal Interface capacity (in cents per kWh). The same Usage Charge will be used to compensate Scheduling Coordinators who, in effect, create transmission capacity through counter Schedules on Congested Inter-Zonal Interfaces.

27.1.2.1.2 Calculation of Marginal Value of an Inter-Zonal Interface.

The marginal value of an Inter-Zonal Interface is the basis for the Usage Charge associated with the scheduled use of the Inter-Zonal Interface. This price is calculated from the Adjustment Bids of the Scheduling Coordinators and the ISO's computer optimization algorithms, using the procedures described in Section 27.1.1.

27.1.2.1.2.1 The price used to determine the Usage Charge will be the Day-Ahead price for those scheduling in the Day-Ahead Market, or the Hour-Ahead price for those Schedules submitted after the Day-Ahead Market closed.

27.1.2.1.2.2 The Day-Ahead prices are calculated based on the Adjustment Bids of the Scheduling Coordinators who participate in the Day-Ahead Market. These Day-Ahead prices are used to calculate Usage Charges for Schedules accepted in the Day-Ahead Market.

27.1.2.1.2.3 The Hour-Ahead prices are calculated based on Adjustment Bids submitted or otherwise still in effect after the Day-Ahead procedures have concluded. These prices are applied to all Schedules for the use of the Congested Inter-Zonal Interfaces that have been submitted and accepted after the ISO's Day-Ahead scheduling and Congestion Management have concluded.

27.1.2.1.3 Default Usage Charge.

If inadequate or unusable Adjustment Bids have been submitted to the ISO to enable the ISO's Congestion Management to schedule Inter-Zonal Interface capacity on an economic basis, then the ISO will calculate and impose a default Usage Charge, in accordance with Sections 27.1.2.1.3.1 through 27.1.2.1.3.4.

27.1.2.1.3.1 The default Usage Charge will be calculated within a range having an absolute floor of \$0/MWh and an absolute ceiling of \$500/MWh; provided that the ISO may vary the floor within the absolute limits, with day-prior notice (e.g., applicable to next day's Day-Ahead Market) to Scheduling Coordinators, and vary the ceiling within the absolute limits, with at least seven (7) days notice to Scheduling Coordinators.

27.1.2.1.3.2 The default Usage Charge will be calculated, in accordance with this Section 27.1.2.1.3, by applying a pre-set adder, ranging from \$0/MWh to \$99/MWh, to the highest incremental Adjustment Bid used, less the applicable decremental Adjustment Bid used; provided that in all cases where there are insufficient decremental Adjustment Bids or no decremental Adjustment Bids available, in the exercise of mitigating Congestion, the applicable decremental price will be set equal to \$0/MWh; provided, further, that the ISO may vary the pre-set adder with day-prior notice to Scheduling Coordinators (e.g., applicable to next day's Day-Ahead Market).

27.1.2.1.3.3 Upon the ISO Operations Date, and until such time as the ISO determines otherwise, the ceiling price for the default Usage Charge will be set at \$250/MWh; the floor price for the default Usage Charge will be set at \$30/MWh; and the pre-set adder that is to be applied in accordance with Section 27.1.2.1.3.2 will be set at \$0/MWh.

27.1.2.1.3.4 The ISO will develop and implement a procedure for posting default Usage Charges on the WEnet or ISO Home Page.

27.1.2.1.3.5 If the Congestion Management software is not capable of calculating the default Usage Charge upon the ISO Operations Date in accordance with Sections 27.1.2.1.3.1 through 27.1.2.1.3.4, the ISO will establish a fixed default Usage Charge within the absolute limits of \$0/MWh and \$500/MWh, which may be changed by the ISO with day-prior notice. Initially, the default Usage Charge would be capped at \$100/MWh. As soon as tested and available, the ISO will implement the Congestion Management software to calculate the default Usage Charge in accordance with Sections 27.1.2.1.3.1 through 27.1.2.1.3.4 after giving at least seven (7) days notice to Scheduling Coordinators, by way of a notice posted on the ISO Internet "Home Page" at <http://www.ISO.com> or such other Internet address as the ISO may publish from time to time.

27.1.2.1.4 Determination of Usage Charges to be Paid by Scheduling Coordinator.

All Scheduling Coordinators whose Schedules requiring use of a Congested Inter-Zonal Interface have been accepted by the ISO, shall pay a Usage Charge for each hour for which they have been scheduled to use the Inter-Zonal Interface. The amount payable shall be the product of the Usage Charge referred to in Section 27.1.2.1.2 for the particular hour, multiplied by the Scheduling Coordinator's scheduled flows (in kW) and capacity, if any, reserved for Ancillary Services over the Inter-Zonal Interface for that particular hour.

27.1.2.1.5 Determination of Usage Charges to be Paid to Scheduling Coordinators Who Counter-Schedule.

27.1.2.1.5.1 Scheduling Coordinators who in effect create additional Inter-Zonal Interface transmission capacity on Congested Inter-Zonal Interfaces will receive from the ISO a Usage Charge for each hour they have counter-scheduled on the Congested Inter-Zonal Interfaces. The amount payable shall be the product of the Usage Charge referred to in Section 27.1.2.1.2 for that particular hour, multiplied by the Scheduling Coordinator's scheduled flows.

27.1.2.1.5.2 If a Scheduling Coordinator fails to provide the scheduled flows in a counter direction, it must reimburse the ISO for the ISO's costs of buying or selling Imbalance Energy in each of the Zones affected by the non-provided scheduled flows in a counter direction, at the ISO's Zonal Imbalance Energy prices. That is, any Scheduling Coordinator that does not produce, in real time, the amount of Energy scheduled in the Day-Ahead Market or Hour-Ahead Market will be deemed to have purchased/sold the amount of Energy under/over produced in the real-time imbalance market at the real-time price.

27.1.2.1.6 ISO Disbursement of Net Usage Charge Revenues.

The ISO will determine the net Usage Charges on an interface-by-interface basis by subtracting the Usage Charge fees paid to Scheduling Coordinators from the Usage Charge fees paid by Scheduling Coordinators. The net Usage Charge revenues collected by the ISO for each Inter-Zonal Interface shall be, subject to the provisions of Section 27.1.2.1.7 of the ISO Tariff, paid to: (i) FTR Holders, in accordance with Section 36.6; and (ii) to the extent not paid to FTR Holders, to Participating TOs who

own the Inter-Zonal Interfaces and Project Sponsors as provided in Section 24.7.3 (in proportion to their respective ownership rights). If a New Participating TO has received FTRs, pursuant to Section 36.4.3, over an Inter-Zonal Interface, the MW of FTRs received shall not be eligible for the disbursement of Usage Charge revenues under part (ii) of this section. Participating TOs will credit in turn the Usage Charge revenue to their Transmission Revenue Balancing Accounts, or, for those Participating TOs that do not have such accounts, to their Transmission Revenue Requirements.

27.1.2.1.7 ISO Debit of Net Usage Charge Revenues.

If, after the issuance of Final Day-Ahead Schedules by the ISO, (a) Participating TOs instruct the ISO to reduce interface limits based on operating conditions or (b) an unscheduled transmission Outage occurs and as a result of either of those events, Congestion is increased and Available Transfer Capacity is decreased in the Inter-Zonal Interface in the Hour-Ahead Market, the ISO shall: (1) charge each Participating TO and Project Sponsor(s) as provided in Section 24.7.3, and FTR Holder with an amount equal to its proportionate share, based on its financial entitlement to Usage Charges in the Day-Ahead Market in accordance with Section 27.1.2.1.6, of the product of (i) the Usage Charge in the Day-Ahead Market and (ii) the reduction in Available Transfer Capacity across the Inter-Zonal Interface in the direction of the Congestion (such amount due to the Participating TOs to be debited by them in turn from their Transmission Revenue Balancing Accounts or, for those Participating TOs that do not have such accounts, to their Transmission Revenue Requirements); (2) charge each Scheduling Coordinator with its proportionate share, based on Schedules in the Day-Ahead Market across the Inter-Zonal Interface in the direction of the Congestion, of the difference between the amount charged to Participating TOs and Project Sponsors as provided in Section 24.7.3, and FTR Holders under clause (1) and the Usage Charges in the Hour-Ahead Market associated with the reduced Available Transfer Capacity across the Congested Inter-Zonal Interface; and (3) credit each Scheduling Coordinator whose Schedule in the Hour-Ahead Market for the transfer of Energy across the Congested Inter-Zonal Interface was adjusted due to the reduction in Available Transfer Capacity an amount equal to the product of the adjustment (in MW) and the Usage Charge in the Hour-Ahead Market (in\$/MW).

The ISO will issue a notice to Scheduling Coordinators of the operating hour, and extent, for which the

derate will apply in the relevant Hour-Ahead Markets. The timing and form of such notices shall be set forth in ISO procedures.

27.1.3 Grid Operations Charge for Intra-Zonal Congestion.

Scheduling Coordinators whose resources are Redispatched by the ISO, in accordance with Intra-Zonal Congestion Management as set forth in Section 27.1.1.6, will be paid or charged as set forth in Appendix N, Part B. The net Redispatch cost will be recovered for each Settlement Period through the Grid Operations Charge, which shall be paid to the ISO by all Scheduling Coordinators in proportion to their metered Demands within the Zone with Intra-Zonal Congestion, and scheduled exports from the Zone with Intra-Zonal Congestion to a neighboring Control Area, provided that, with respect to Demands within an MSS in the Zone and scheduled exports from the MSS to a neighboring Control Area, a Scheduling Coordinator shall be required to pay Grid Operations Charges only with respect to Intra-Zonal Congestion, if any, that occurs on an interconnection between the MSS and the ISO Controlled Grid, and with respect to Intra-Zonal Congestion that occurs within the MSS, to the extent the Congestion is not relieved by the MSS Operator.

27.2.1 Transmission Losses.

27.2.1.1 Obligation to Provide for Transmission Losses.

Each Scheduling Coordinator shall ensure that it schedules sufficient Generation to meet both its Demand and Transmission Losses responsibilities as determined in accordance with this Section 27.2.1. Scheduling Coordinators for Generators, System Units and System Resources are responsible for their respective proportion of Transmission Losses as determined in accordance with Section 27.2.1.2. For each Final Hour-Ahead Schedule, each Scheduling Coordinator representing Generators, dynamically scheduled System Resources or System Units shall elect through the flag described in Section 30.2.2 to either: 1) generate sufficient additional energy to meet its respective Transmission Losses or 2) be financially responsible for its respective transmission loss obligation based on the Imbalance Energy procured on its behalf by the ISO. Scheduling Coordinators for non-dynamically scheduled System Resources may self-provide transmission losses by scheduling an additional balanced quantity of Energy, both Supply and Demand, equal to their expected transmission loss obligation above their committed

delivery quantities in their Hour-Ahead Schedules. In the ISO Imbalance Energy market, all Scheduling Coordinators for Generators, System Units, and System Resources must be financially responsible for all respective Transmission Losses associated with their respective Imbalance Energy Dispatch Instructions in real time, based on the Imbalance Energy procured on their behalf by the ISO. A Scheduling Coordinator for an MSS Operator that has elected to follow Load will be responsible for its transmission loss obligation pursuant to Sections 4.9.9.1 and 4.9.16.4.

27.2.1.1.1 Settlement of Transmission Loss Obligations.

For a Scheduling Coordinator that elects to not or may not, self-provide for its transmission loss obligation, the ISO will procure Imbalance Energy on the Scheduling Coordinator's behalf for each relevant Dispatch Interval and explicitly settle its transmission loss obligation for each applicable Settlement Interval. For a resource under an ISO Dispatch Instruction for Imbalance Energy, transmission loss obligations shall be settled at the Resource-Specific Settlement Interval Ex Post Price. For a resource not under an ISO Dispatch Instruction for Imbalance Energy, transmission loss obligations shall be settled at the simple average of the two applicable Dispatch Interval Ex Post Prices as defined in Section 34.9.2.1. Allocation of transmission loss obligation settlement shall be treated consistent with Instructed Imbalance Energy pursuant to Section 11.2.4.2.1.

27.2.1.2 Determination of Transmission Losses.

The ISO will specify GMMs for each Energy supply source (Generating Units and external imports at Scheduling Points) to account for the Energy lost in transmitting power from Generating Units and/or Scheduling Points to Load. The total Demand that may be served by a Generating Unit, in a given hour, taking account of Transmission Losses, is equal to the product of the total Metered Quantity of that Generating Unit in that hour and the Ex Post Generation Meter Multiplier calculated by the ISO in the hour for that Generator location except in accordance with Section 27.2.1.2.3. The Ex Post Generation Meter Multiplier shall be greater than one (1) where the Generating Unit's contribution to the ISO Controlled Grid reduces Transmission Losses and shall be less than one (1) where the Generating Unit's contribution to the system increases Transmission Losses. All Generating Units supplying Energy to the ISO Controlled Grid at the same electrical bus shall be assigned the same Ex Post Generation Meter Multiplier. Inter-

Scheduling Coordinator Energy Trades will not be subject to such adjustments, beyond the impact of GMMs on the respective Scheduling Coordinator's Generation and external imports.

27.2.1.2.1 Procedures for Calculating Generation Meter Multiplier.

27.2.1.2.1.1 At all times, the ISO will make available Generating Meter Multipliers for the seven Trading Days starting with the Trading Day after the next Trading Day before Scheduling Coordinators submit Day-Ahead Preferred Schedules. By 6:00 p.m. two days preceding a Trading Day, the ISO will calculate, and post on WEnet, an estimated Generation Meter Multiplier for each electrical bus at which one or more Generating Units may supply Energy to the ISO Controlled Grid. In other words, if the current Trading Day is day 0, the ISO will publish at 6:00 pm today, via WEnet, the GMMs for Trading Days 2 through 8. On Trading Day 1, at 6:00 pm, the ISO will drop the GMMs for Trading Day 1 and add the newly calculated GMMs for Trading Day 9, with the GMMs for Trading Days 3 through 8 remaining the same.

27.2.1.2.1.1.1 The Generation Meter Multipliers shall be determined utilizing the Power Flow Model based upon the ISO's forecasts of total Demand for the ISO Controlled Grid and Demand and Generation patterns throughout the ISO Controlled Grid. The ISO will calculate and publish GMMs for each Settlement Period to reflect different expected Generation and Demand patterns and expected operations and maintenance requirements, such as line Outages, which could affect Transmission Loss determination and allocation. The ISO shall continuously update the data to be used in calculating the Generation Meter Multipliers to reflect changes in system conditions on the ISO Controlled Grid, and the ISO shall provide all Scheduling Coordinators with access to such data. The ISO shall not be required to determine new Generation Meter Multipliers for each hour; the ISO will determine the appropriate period for which each set of Generation Meter Multipliers will apply, which period may vary based upon the expected frequency and magnitude of changes in system conditions on the ISO Controlled Grid.

27.2.1.2.1.2 The ISO will calculate the Ex Post Generation Meter Multiplier for each electrical bus at which one or more Generating Units may supply Energy to the ISO Controlled Grid. The Ex Post Generation Meter Multipliers shall be determined utilizing the real-time Power Flow Model based upon the ISO's total Demand for the ISO Controlled Grid and Demand and Generation patterns throughout the ISO Controlled Grid. The ISO's total Demand shall be determined using real-time power flow data based on a state-estimation result. Any difference between scheduled and Ex Post Transmission Losses will be considered as an Imbalance Energy deviation and will be purchased or sold in the Real Time Market at the Settlement Interval Ex Post Price.

27.2.1.2.2 Methodology for Calculating Generation Meter Multiplier.

The ISO shall calculate the Generation Meter Multiplier for each Generating Unit location in a given hour by subtracting the Scaled Marginal Loss Rate from 1.0.

27.2.1.2.2.1 The Scaled Marginal Loss Rate for a given Generating Unit location in a given hour shall equal the product of (i) the Full Marginal Loss Rate for each Generating Unit location and hour, and (ii) the Loss Scale Factor for such hour.

27.2.1.2.2.2 The ISO shall calculate the Full Marginal Loss Rate for each Generating Unit location for an hour by utilizing the Power Flow Model to calculate the effect on total Transmission Losses for the ISO Controlled Grid of injecting an increment of Generation at each such Generating Unit location to serve an equivalent incremental MW of Demand distributed on a pro-rata basis throughout the ISO Controlled Grid.

27.2.1.2.2.3 The ISO shall determine the Loss Scale Factor for an hour by determining the ratio of forecast Transmission Losses to the total Transmission Losses which would be collected if Full Marginal Loss Rates were applied to each Generating Unit in that hour.

27.2.1.2.3 In the event that the Power Flow Model fails to determine Ex Post GMMs, for example if GMMs are outside the range of reasonability (typically 0.8 to 1.1), the ISO will use Default GMMs in their place.

27.2.2 Generation Meter Multipliers

27.2.2.1 Temporary Simplification Relating to GMM Loss Factors Application

Notwithstanding any other provision in the ISO Tariff, including the ISO Protocols, in determining whether a Schedule is a Balanced Schedule, no allowance shall be made for Transmission Losses (i.e., the Generation Meter Multiplier shall be set at 1.0) for all Scheduling Coordinators.

27.2.2.2 Application.

Notwithstanding any other provision in this Tariff, including the ISO Protocols, the temporary simplification measure specified in this Section 27.2.2 shall have effect until discontinued by a Notice of Full-Scale Operations issued by the Chief Executive Officer of the ISO.

27.2.2.2.1 Pursuant to Subsections 27.2.2.3.1 and 27.2.2.3.2, the Chief Executive Officer of the ISO shall give notice to all Scheduling Coordinators that such Scheduling Coordinators shall use forecasted Generation Meter Multipliers, as published by the ISO, in their Schedules. Such notice shall be given only after the Chief Executive Officer determines that the ISO is capable of accepting Schedules using the forecasted Generation Meter Multipliers without adversely affecting operations or reliability.

27.2.2.3 Notices of Full-Scale Operations.

27.2.2.3.1 When the Chief Executive Officer of the ISO determines that the ISO is capable of implementing this Tariff, including the ISO Protocols, without modification in accordance with a temporary simplification measure specified in this Section 27.2.2, he shall issue a notice ("Notice of Full-Scale Operations") and shall specify the relevant temporary simplification measure and the date on which it will permanently cease to apply, which date shall be not less than seven (7) days after the Notice of Full-Scale Operations is issued.

27.2.2.3.2 A Notice of Full-Scale Operations shall be issued when it is posted on the ISO Internet "Home Page," at <http://www.ISO.com> or such other Internet address as the ISO may publish from time to time.

28 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;

29 [NOT USED]

30 BIDS AND BID SUBMISSION.

30.1 ISO Operations.

30.1.1 Scheduling.

30.1.3 ISO Scheduling Responsibilities.

To fulfill its obligations with respect to scheduling Energy and Ancillary Services, the ISO shall:

- (a) provide Scheduling Coordinators with operating information and system status on a Day-Ahead and Hour-Ahead, Zonal and/or Scheduling Point basis to enable Scheduling Coordinators to optimize Generation, Demand and the provision of Ancillary Services;
- (b) determine whether Preferred Schedules submitted by Scheduling Coordinators meet the requirements of Section 4.5.4.2, and whether they will cause Congestion;
- (c) prepare Suggested Adjusted Schedules on a Day-Ahead basis and Final Schedules on a Day-Ahead and Hour-Ahead basis;
- (d) validate all Ancillary Services bids and self-provided Ancillary Services;
- (e) reduce or eliminate Inter-Zonal Congestion based on Adjustment Bids and in accordance with the Congestion Management procedures, and Intra-Zonal Congestion in accordance with Section 27.1.1.6;
and
- (f) if necessary, make mandatory adjustments to Schedules in accordance with the Congestion Management procedures.

30.2 Information to Be Submitted by Scheduling Coordinators to the ISO.

Scheduling Coordinators must comply with the ISO Data Templates and Validation Rules Document, which contains the format for submission of Schedules and bids. Each Preferred Schedule submitted by a Scheduling Coordinator shall represent its preferred mix of Generation to meet its Demand and account for Transmission Losses and must include the name and identification number of each Eligible Customer for whom a Demand Bid or an Adjustment Bid is submitted, as well as:

30.2.1 For Demand:

30.2.1.1 Designated Location Code. For all Demand the Location Code of the Take-Out Point

(which must be the name of a Demand Zone, Load group or bus);

30.2.1.2 Quantity at Take-Out Point. The aggregate quantity (in MWh) of Demand being served at each Take-Out Point for which a bid has been submitted;

30.2.1.3 Flexibility. Whether the Preferred Schedule is flexible for adjustment to eliminate Congestion;

30.2.1.4 Adjustment Bids. The MW and \$/MWh values representing the Adjustment Bid curve for any Dispatchable Load;

30.2.1.5 Scheduling Coordinator's ID code;

30.2.1.6 type of market (Day-Ahead or Hour-Ahead) and Trading Day;

30.2.1.7 type of Schedule: Preferred or Revised;

30.2.1.8 hourly scheduled MWh for each Settlement Period of the Trading Day that uses the Existing Contract (which values should be less than or equal to the values indicated in (i) 30.2.1.12 below);

30.2.1.9 Congestion Management flag. "Yes" indicates that any Adjustment Bid submitted for a Dispatchable Load under item 30.2.1.12 below should be used;

30.2.1.10 publish Adjustment Bid flag, which will not be functional on the ISO Operations Date. In the future, "Yes" will indicate that the Scheduling Coordinator wishes the ISO to publish its Adjustment Bids;

30.2.1.11 hourly scheduled MWh, including any zero values, for each Settlement Period of the Trading Day (in the case of a Day-Ahead Schedule) and for the relevant Settlement Period (in the case of an Hour-Ahead Schedule);

30.2.1.12 the MW and \$/MWh values for each Dispatchable Load for which an Adjustment Bid is being submitted;

30.2.1.13 requisite NERC tagging data.

30.2.2 For Generation:

30.2.2.1 Location of Generating Units. The Location Code of all Generating Units scheduled, if applicable, or the source Control Area and Scheduling Point;

30.2.2.2 Quantity Scheduled. The aggregate quantity (in MWh) being scheduled from each Generating Unit and System Resource;

30.2.2.3 Notification of Flexibility. Notification of whether the Preferred Schedule is flexible for adjustment to eliminate Congestion;

30.2.2.4 Adjustment Bids. The MW and \$/MWh values representing the Adjustment Bid curve for each Generating Unit and System Resource for which an Adjustment Bid has been submitted;

30.2.2.5 Operating Characteristics. Operating characteristics for each Generating Unit and System Resource for which an Adjustment Bid has been submitted; and

30.2.2.6 Must-Take/Must-Run Generation. Identification of all scheduled Generating Units that are Regulatory Must-Take Generation or Regulatory Must-Run Generation.

30.2.2.7 Scheduling Coordinator's ID code;

30.2.2.8 type of market (Day-Ahead or Hour-Ahead) and Trading Day;

30.2.2.9 name of Generating Unit scheduled;

30.2.2.10 type of Schedule: Preferred or Revised;

30.2.2.11 priority type, if applicable, to the Settlement Period (use OTHER if scheduling the use of Existing Contract rights or RLB_MUST_RUN) for Reliability Must-Run Generation;

30.2.2.12 contract reference number for Reliability Must-Run Generation;

30.2.2.13 Transmission loss self-provision flag (LOSS CMP FLG): "Yes" indicates that Dispatch Instructions provided to the Generating Unit will include Transmission Losses associated with the unit's Final Hour-Ahead Schedule as determined by the relevant GMM;

30.2.2.14 Congestion Management flag. "Yes" indicates that any Adjustment Bid submitted

under 30.2.2.15 should be used in the Day-Ahead or Hour-Ahead Market;

30.2.2.14A Publish Adjustment Bid flag, which will not be functional on the ISO Operations

Date. In the future, "Yes" will indicate that the Scheduling Coordinator wishes the ISO to publish its Adjustment Bids;

30.2.2.15 Generating Unit ramp rate in MW/minute;

30.2.2.16 hourly scheduled Generating Unit output in MWh (the ISO will multiply these values by the hourly Generation Meter Multipliers), including any zero values, for each Settlement Period of the Trading Day (in the case of a Day-Ahead Schedule) and for the relevant Settlement Period (in the case of an Hour-Ahead Schedule);

30.2.2.17 The MW and \$/MWh values for each Generating Unit for which an Adjustment Bid is being submitted.

30.2.2A The Generation section of a Balanced Schedule, and any associated Adjustment Bids, must accurately reflect the physical capability of each Generating Unit identified in the Schedule (including each Generating Unit's ability to ramp from one hour to the next). For example, a 500 MW Generating Unit specified with a ramp rate of 2 MW/min and an operating point of 100 MWh for the current operating hour is not physically capable of generating 300 MWh in the next operating hour. Likewise, Adjustment Bids submitted for a Generating Unit, applicable to a particular operating hour, should be physically achievable within the applicable operating hour.

30.2.3 For deliveries to/from other Scheduling Coordinators:

In the event of an Inter-Scheduling Coordinator Energy Trade, the Scheduling Coordinators who are parties to that trade must agree on a Zone in which the trade will be deemed to take place and notify the ISO accordingly. The purpose of designating a Zone is to provide for the allocation of Usage Charges which may arise in connection with the trade. The Inter-Scheduling Coordinator Energy Trades section of a Schedule will include the following information for each Inter-Scheduling Coordinator Trade:

30.2.3.1 Identification Code. Identification Code of Scheduling Coordinator to which Energy is provided or from which Energy is received;

- 30.2.3.2** **Quantity of Energy.** Quantity (in MWh) of Energy being received or delivered;
- 30.2.3.3** **Zone.** The Zone within which Energy is deemed to be provided by one Scheduling Coordinator to another under the Inter-Scheduling Coordinator Energy Trades.
- 30.2.3.4** **Adjustments.** Scheduling Coordinators will have the opportunity to resubmit Preferred Schedules and or Revised Schedules upon notice by the ISO if the ISO determines that the quantity or location of the receiving Scheduling Coordinator is not consistent with the quantity or location of the delivering Scheduling Coordinator. If the Scheduling Coordinators involved in a mismatched Inter-Scheduling Coordinator Energy Trade do not submit adjusted Schedules which resolve any mismatch as to quantities and provided that there is no dispute as to whether the mismatched trade occurred or over its location, the ISO will adjust the Schedule containing the higher quantity to match the scheduled quantity of Energy in the other Schedule, except where the Schedule to be reduced contains only Inter-Scheduling Coordinator Energy Trades, in which case the ISO will adjust the other Schedule to match the Schedule containing the higher quantity. If there is a dispute between the Scheduling Coordinators as to whether the Inter-Scheduling Coordinator Energy Trade occurred or over its location, the ISO will remove the disputed trade from the Schedules in which it appears. The ISO will then balance the Schedules which are no longer Balanced Schedules by adjusting resources in the relevant Scheduling Coordinator's portfolio.
- 30.2.3.5** The Generating Unit or Dispatchable Load that the source or recipient of Energy traded.
- 30.2.3.6** The MW and \$/MWh values representing the Adjustment Bid for any Generating Unit or Dispatchable Load that is the source or recipient of Energy traded.
- 30.2.3.7** **[Not Used]**
- 30.2.3.8** type of market (Day-Ahead or Hour-Ahead) and Trading Day;
- 30.2.3.9** trading Scheduling Coordinator (buyer or seller);
- 30.2.3.10** type of Schedule: Preferred or Revised;
- 30.2.3.11** Schedule type – Energy (ENGY);

30.2.3.12 hourly scheduled MWh, including any zero values, for each Settlement Period of the Trading Day (in the case of a Day-Ahead Schedule) and for the relevant Settlement Period (in the case of an Hour-Ahead Schedule), with internal imports into the Scheduling Coordinator reported as negative quantities and internal exports from the Scheduling Coordinator reported as positive quantities;

30.2.3.13 Congestion Management flag – “Yes” indicates that Adjustment Bid submitted under (k) below should be used:

30.2.3.14 publish Adjustment Bid flag – “Yes” indicates that the Scheduling Coordinator wishes the ISO to publish its Adjustment Bid.

30.2.4 For Self-Provided Ancillary Services:

Scheduling Coordinators electing to self-provide Ancillary Services shall supply the information referred to in Section 8.6.4 in relation to each Ancillary Service to be self-provided.

30.2.5 For Interruptible Imports:

The quantity (in MWh) of Energy categorized as Interruptible Imports and whether the Scheduling Coordinator intends to self-provide the Operating Reserve required by Section 8.2.3.2 to cover such Interruptible Imports or to purchase such Operating Reserve from the ISO.

30.2.6 For External Imports/Exports:

The external import/export section of a Balanced Schedule will include the following information for each import or export:

30.2.6.1 Scheduling Coordinator’s ID code;

30.2.6.2 type of market (Day-Ahead or Hour-Ahead) and Trading Day;

30.2.6.3 Scheduling Point (the name);

30.2.6.4 type of Schedule: Preferred or Revised

30.2.6.5 interchange ID (the name of the selling entity, the buying entity, and a numeric identifier);

- 30.2.6.6** Energy type – firm (FIRM), non-firm (NFRM) or dynamic (DYN) or Wheeling (WHEEL);
- 30.2.6.7** external Control Area ID;
- 30.2.6.8** priority type, if applicable, to the Settlement Period (use OTHER if scheduling the use of Existing Contract rights or RLB_MUST_RUN for Reliability Must-Run Generation);
- 30.2.6.9** contract reference number for Reliability Must-Run Generation or Existing Contract (or set of interdependent Existing Contracts);
- 30.2.6.10** contract type – transmission (TRNS), Energy (ENGY) or both (TR_EN);
- 30.2.6.11** Schedule ID (NERC ID number);
- 30.2.6.12** Congestion Management flag – “Yes” indicates that any Adjustment Bid submitted for an external import/export in item (q) below should be used;
- 30.2.6.13** publish Adjustment Bid flag, which will not be functional on the ISO Operations Date. In the future, “Yes” will indicate that the Scheduling Coordinator wishes the ISO to publish its Adjustment Bids;
- 30.2.6.14** Complete NERC tag;
- 30.2.6.15** hourly scheduled external imports/exports in MWh (the ISO will multiply these values by the hourly Generation Meter Multipliers), including any zero values, for each Settlement Period of the Trading Day (in the case of a Day-Ahead Schedule) and for the relevant Settlement Period (in the case of an Hour-Ahead Schedule) and with external imports into the ISO Controlled Grid reported as negative quantities and external exports from the ISO Controlled Grid reported as positive quantities;
- 30.2.6.16** the MW and \$/MWh values for each external import/export for which an Adjustment Bid is being submitted consistent with Section 30.2.8;
- 30.2.6.17** for dynamically scheduled imports only, the transmission loss self-provision flag (LOSS_CMP_FLG): “Yes” indicates that Dispatch Instructions provided to the resource will include Transmission Losses associated with the resource’s Final Hour-Ahead Schedule as determined by the relevant GMM.

30.2.7 Contract Usage Template Associated with a Balanced Schedule that Includes the Use of Existing Contract Rights or Firm Transmission Rights.

The contract usage template can be submitted seven days in advance. However, the contract usage template will not be validated till the trade day. Each contract usage template must include the following information, in compliance with the ISO Data Templates and Validation Rules document which contains the format for submission of contract usage templates:

30.2.7.1 Scheduling Coordinator's ID code:

30.2.7.2 Type of market (Day-Ahead or Hour-Ahead) and Trading Day;

30.2.7.3 From Zone (must be different than "to Zone"), is the Zone in which all sources specified in the contract usage template must be located;

30.2.7.4 To Zone (must be different than "from Zone"), is the Zone in which all sinks specified in the contract usage template must be located;

30.2.7.5 Contract reference number for each Inter-Zonal Interface for which transmission capacity has been reserved under Existing Contract or Firm Transmission Right. Up to four contract reference numbers can be specified in this field, delimited by commas, for either Existing Contract usage or Firm Transmission Right usage, but not for both (i.e. Existing Contract rights and Firm Transmission Rights cannot be used together in linking sources and sinks on contract usage template). If the use of multiple Inter-Zonal Interfaces are being scheduled, the contract reference numbers must represent a contiguous string of contracts rights from one Zone to the next (although the contract reference numbers need not be listed in any particular order since they will be arranged by the ISO's scheduling program to connect the "from Zone" to "to Zone");

30.2.7.6 Usage ID (a unique identifier that allows a Scheduling Coordinator to submit multiple usages for a given Inter-Zonal Interface);

30.2.7.7 Contract usage, in hourly scheduled MW, for the 24 hours of the Trading Day (for Generators, contract usage can be either positive or negative (i.e., for pumps); for loads, contract usage must be positive; for external imports and inter-Scheduling Coordinator trade imports, contract usage

must be negative; for external exports, contract usage must be positive). Each contract usage amount must be less than or equal to the amount of Existing Contract rights specified by the relevant Participating Transmission Owner(s) of Firm Transmission Rights, whichever the case may be. Additionally, any Adjustment Bids that may also be submitted for any particular resource (source or sink) that is also identified on a contract usage template must not overlap the contract usages specified for a particular resource in a contract usage template;

30.2.7.8 Priority usage, relative to all contract usages specified in a Scheduling Coordinator's Balanced Schedule, as expressed on a scale of one to ten (with 1 having least priority and 10 having highest priority). For Existing Contracts, this priority will be used to adjust usage quantities when scheduled usages exceed the reserved existing transmissions reservations; and

30.2.7.9 Sources or sinks, of hourly scheduled MWh (in the case of Energy usages) or MW (in the case of Ancillary Services usages), specified on the contract usage template must be balanced (except for Ancillary Services which need not be specified with sinks). Each Energy schedule or Ancillary Service bid or self-provided schedule associated with a particular source or sink must have an hourly usage schedule that is greater than or equal to the amounts specified on contract usage templates. The source/sink section of a contract usage template will include the following information (up to five combinations of sources and sinks can be specified on a single contract usage template if an Scheduling Coordinator is submitting the templates in accordance with Section 6.4.1A.3, or up to 20 combinations of sources and sinks if an Scheduling Coordinator is submitting the templates in accordance with Section 6.4.1A.3;

- (1) Type of resource – Generation (GEN), load (LOAD), interchange (INTRCHANGE) or inter-Scheduling Coordinator trade (INTER_Scheduling Coordinator);
- (2) Resource_ID – generator_ID, load_ID, tie_point or trading Scheduling Coordinator;
- (3) Resource_ID2 (required only for individual interchange schedules and inter-Scheduling Coordinator trades);
- (4) Energy type – firm (FIRM), non-firm (NFIRM), Wheeling (WHEEL), dynamic (DYN),

Energy (ENGY), Spinning Reserve (CSPN), Non-Spinning Reserve (CNSPN) or Replacement Reserve (CRPLC); and

- (5) Hourly scheduled Energy or Ancillary Service, utilizing the same sign convention as set forth in (g) above.

30.2.8 Content and Format of Adjustment Bids

30.2.8.1 Adjustment Bids are contained in Preferred Schedules and Revised Schedules submitted by Scheduling Coordinators for particular Generating Units (including Physical Scheduling Plants), Dispatchable Loads, external imports/exports, and Generating Units and Dispatchable Loads supporting Inter-Scheduling Coordinator Energy Trades. Each Scheduling Coordinator is required to submit a preferred operating point for each Generating Unit, Dispatchable Load and external import/export (these quantities are presented in the Scheduling Coordinator's submitted Schedule as "Hourly MWh"). The Scheduling Coordinator's preferred operating point for each Generating Unit, Dispatchable Load and external import/export must be within the range of any Adjustment Bids to be used by the ISO. The minimum MW output level, which may be zero MW (or negative for pumped storage resources), and the maximum MW output level must be physically achievable.

30.2.8.2 Adjustment Bids will be presented in the form of a monotonically non-decreasing staircase function for Generating Units and external imports. Adjustment Bids will be presented in the form of a monotonically non-increasing staircase function for Dispatchable Loads and external exports. These staircase functions will be composed of up to eleven (11) ordered pairs (i.e., ten (10) steps or price bands) of quantity/price information. Adjustment Bids are submitted as an integral part of the Scheduling Coordinator's Balanced Schedule and must be related to each Generating Unit, Dispatchable Load and external import/export.

30.2.9 Scheduling Coordinators must comply with the ISO Data Templates and Validation Rules document, which contains the format for submission of Schedules and bids.

30.3 The Scheduling Process.

The ISO scheduling process is described for information purposes only in tabular form in Appendix C.

The scheduling process by nature will need constant review and amendment as the market develops and matures and, therefore, is subject to change. The description in Appendix C aids understanding of the implementation and operation of the various markets administered by the ISO and is filed for information purposes only.

30.3.1 Preferred Schedule.

A Preferred Schedule is the initial Schedule submitted by a Scheduling Coordinator in the Day-Ahead Market or Hour-Ahead Market. A Preferred Schedule shall be a Balanced Schedule submitted by each Scheduling Coordinator on a daily and/or hourly basis to the ISO. Scheduling Coordinators may also submit to the ISO, Ancillary Services bids in accordance with Section 8.5.2 and, where they elect to self-provide Ancillary Services pursuant to Section 8.6.1, an Ancillary Service schedule meeting the requirements set forth in Section 8.6.4.2A.

30.3.1A The Preferred Schedule shall also include Adjustment Bids as an indication of which resources (Generation or Load) if any may be adjusted by the ISO to eliminate Congestion. Adjustment Bids will be used by the ISO for Inter-Zonal Congestion Management as described in the SP and are initially valid only for the markets into which they are bid, being the Day-Ahead Market or the Hour-Ahead Market. During the ISO's Day-Ahead scheduling process, in accordance with the SP, the MW range of the Adjustment Bids specified in the Preferred Day-Ahead Schedule, but not the price values, may be changed by the Scheduling Coordinator in its Revised Day-Ahead Schedule, if any. These Adjustment Bids will not be transformed into Supplemental Energy bids.

30.3.2 Seven-Day Advance Schedules.

Scheduling Coordinators may submit Balanced Schedules for up to seven (7) Trading Days at a time, representing the Scheduling Coordinator's Preferred Schedule for each Day-Ahead Market and/or Hour-Ahead Market. These advance Schedules can be overwritten by new Preferred Schedules at any time prior to the deadline for submitting Day-Ahead Schedules and Hour-Ahead Schedules, as described in the SP. If not overwritten by the Scheduling Coordinator, a Schedule submitted in advance of this deadline for submission will become the Scheduling Coordinator's Preferred Schedule at the deadline for submitting Day-Ahead Schedules and/or Hour-Ahead Schedules. There is no validation of Schedules

submitted in advance of the deadline for submitting Preferred Schedules.

30.3.3 Suggested Adjusted Schedules.

In the Day-Ahead scheduling process, if the sum of Scheduling Coordinators' Preferred Schedules would cause Congestion across any Inter-Zonal Interface, the ISO shall issue to all Scheduling Coordinators an estimate of the Usage Charges if Congestion is not relieved and Suggested Adjusted Schedules that shall reflect adjustments made by the ISO to each Scheduling Coordinator's Preferred Schedule to eliminate Congestion, based on the initial Adjustment Bids submitted in the Preferred Schedules. The ISO will include in the Suggested Adjusted Schedules the resolution of any mismatches in Inter-Scheduling Coordinator Energy Trades, as determined by the ISO. These Suggested Adjusted Schedules will not apply to uses of transmission owned by Non-Participating TOs nor to uses of Existing Rights. A modification flag, set by the ISO, will indicate whether the scheduled output in a Settlement Period has been modified as a result of Congestion Management.

30.3.4 Revised Schedules.

Following receipt of a Suggested Adjusted Schedule, a Scheduling Coordinator may submit to the ISO a Revised Schedule, which shall be a Balanced Schedule, and which shall seek to reduce or eliminate Congestion. There are no Revised Schedules in the Hour-Ahead Market.

30.3.4.1 Final Schedules.

If the ISO notifies a Scheduling Coordinator that there will be no Congestion on the ISO Controlled Grid based on the Preferred Schedules submitted by all Scheduling Coordinators, then subject to Section 30.2.3.4, the Preferred Schedule shall become that Scheduling Coordinator's Final Schedule. If the ISO has issued Suggested Adjusted Schedules and if no Scheduling Coordinator submits any changes to the Suggested Adjusted Schedules, all of the Suggested Adjusted Schedules shall become the Final Schedules. If the ISO has adjusted the Scheduling Coordinator's Preferred Schedule to match Inter-Scheduling Coordinator Energy Trades then the adjusted Preferred Schedule shall become that Scheduling Coordinator's Final Schedule.

If the ISO notifies a Scheduling Coordinator that there will be no Congestion on the ISO Controlled Grid

based on the Revised Schedules submitted by all Scheduling Coordinators, the Revised Schedule shall become that Scheduling Coordinator's Final Schedule. If the ISO has adjusted the Scheduling Coordinator's Revised Schedule to match Inter-Scheduling Coordinator Energy Trades then the adjusted Revised Schedule shall become that Scheduling Coordinator's Final Schedule. If there is Congestion based on the Revised Schedules or mismatches in Inter-Scheduling Coordinator Energy Trades, the ISO shall adjust the Revised Schedules and issue Final Schedules. The Scheduling Coordinators will be notified, via WEnet, that their Schedules have become final. The ISO will also publish a final set of Usage Charges for Energy transfers between Zones, applicable to all Scheduling Coordinators. The Final Schedules shall serve as the basis for Settlement between the ISO and each Scheduling Coordinator.

30.3.4.2 Scheduling and Real-Time Information.

30.3.4.3 Final Schedules.

The scheduling process described in Section 30.3 will produce for the ISO real-time dispatchers for each Settlement Period of the Trading Day a Final Schedule consisting of the combined commitments contained in the Final Day-Ahead Schedules and the Final Hour-Ahead Schedules for the relevant Settlement Period.

30.3.4.4 The Final Schedule will include information with respect to:

- (a) Generation schedules;
- (b) Demand schedules;
- (c) Ancillary Services schedules based on the ISO's Ancillary Services auction;
- (d) Ancillary Services schedules, based on Scheduling Coordinators ISO accepted schedules and forecast load, for self-provided Ancillary Services;
- (e) Interconnection schedules between the ISO Control Area and other Control Areas; and
- (f) Inter-Scheduling Coordinator Energy Trades.

30.3.5 Prohibition on Scheduling Across Out-of-Service Transmission Paths.

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 its 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, 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).

Mismatches in Inter-Scheduling Coordinator Ancillary Service Trades shall be adjusted to be equal to the amount specified by the selling Scheduling Coordinator. A Scheduling Coordinator can also check whether its Schedules will pass the ISO's stage two validation by manually initiating validation of its Preferred Schedules or Revised Schedules, at any time prior to the deadline for submission of Preferred Schedules or Revised Schedules (as the case may be). It is the Scheduling Coordinator's responsibility to perform such checks, if desired. The Scheduling Coordinator will be notified immediately through WEnet of any validation errors. For each error detected, an error message will be generated by the ISO in the Scheduling Coordinator's notification screen which will specify the nature of the error. If the ISO detects a mismatch in Inter-Scheduling Coordinator Trades, the ISO will notify both Scheduling Coordinators of the mismatch in Energy quantity and/or location. 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. The Scheduling Coordinator is also notified of successful validation via WEnet.

30.4.2 Validation of Existing Contract Schedules.

Each Schedule submitted to the ISO by a Scheduling Coordinator representing a rights holder to an Existing Contract must include a valid contract reference number in accordance with Section 16.2.4A.1. If the Schedule includes an Inter-Scheduling Coordinator Trade, only one of the Scheduling Coordinators should submit a contract reference number. If a match of the Schedule's contract reference number is found in the ISO's database and the Schedule is consistent with the instructions submitted previously by the Responsible PTO, the Schedule will be implemented in accordance with the instructions. If a match of the Schedule's contract reference number cannot be found in the ISO's database or if both Scheduling Coordinators which are parties to an Inter-Scheduling Coordinator Trade submit contract reference numbers, the ISO will issue an error message to the Scheduling Coordinator via the WEnet (as described in Section 30.4.1.1) and indicate the nature of the problem. The ISO will assist the Scheduling Coordinator, within reason, in resolving the problem so that the Scheduling Coordinator is able to submit the Schedule successfully as soon as possible within the ISO's timing requirements of the SP. If the Scheduling Coordinator uses a contract reference number for which the responsible PTO has not reserved transmission capacity on a particular path (i.e., the contract reference Number(s) included on a

contract usage template cannot be found in the ISO's scheduling applications table of contract reference numbers), the Scheduled use will be invalidated and the Scheduling Coordinator notified by the ISO's issuance of an invalidated usage information template.

30.4.3 Validation of Adjustment Bids.

30.4.3.1 Invalidation.

The absence of an Adjustment Bid in a Scheduling Coordinator's Preferred Schedule or Revised Schedule will not affect the validation since Scheduling Coordinators are not required to submit Adjustment Bids. If an Adjustment Bid is contained in the Scheduling Coordinator's Preferred Schedule or Revised Schedule but is not in the form described above, both the Schedule and the Adjustment Bid will be rejected. The Scheduling Coordinator will be notified immediately, via WEnet, of any validation errors. For each error detected, an error message will be generated by the ISO in the Scheduling Coordinator's notification screen which will specify the nature of the error. The Scheduling Coordinator can then look at the notification messages to review the detailed list of errors, make changes, and resubmit if it is still within the timing requirements of the SP. The Scheduling Coordinator is also notified of successful validation via WEnet. The Scheduling Coordinators must comply with the ISO Data Templates and Validation Rules document, which contains the validation criteria for Adjustment Bids.

30.4.3.2 Validation Checks.

The ISO's stage one validation checks are performed automatically, whenever Schedules and Adjustment Bids are submitted. The ISO's stage two validation is performed automatically. A Scheduling Coordinator can also check whether its Adjustment Bids will pass the ISO's stage two validation by manually initiating validation of its Preferred Schedule or Revised Schedule, at any time prior to the deadline for submission of Preferred Schedules or Revised Schedules. It is a Scheduling Coordinator's responsibility to perform such checks.

30.4.4 Validation of Ancillary Services Bids.

The ISO will verify that each Ancillary Services Schedule or bid conforms to the format specified for the relevant service. If the Ancillary Services Schedule or bid does not so conform, the ISO will send a

notification to the Scheduling Coordinator notifying the Scheduling Coordinator of the errors in the Schedules and/or bids. Scheduling Coordinators will comply with the ISO Data Templates and Validation Rules document, which contains the validation criteria for Ancillary Services Schedules and bids. Shown below are the two stages of validation carried out by the ISO:

30.4.4.1 Stage One Validation.

During stage one validation, each incoming Ancillary Services schedule or bid will be validated to verify proper content, format and syntax. A technical validation will be performed to verify that a schedule or bid quantity of Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve does not exceed the available capacity for Regulation, Operating Reserves and Replacement Reserve on the Generating Units, System Units, Curtailable Demands and external imports/exports scheduled or bid. The Scheduling Coordinator will be notified immediately through WEnet of any validation errors. For each error detected, an error message will be generated by the ISO in the Scheduling Coordinator's notification screen which will specify the nature of the error. The Scheduling Coordinator can then look at the notification messages to review the detailed list of errors, make changes, and resubmit if it is still within the ISO's timing requirements. The Scheduling Coordinator is also notified of successful validation via WEnet.

30.4.4.2 Stage Two Validation.

Stage two validation will be conducted by the ISO in accordance with Appendix E of the ISO Tariff.

30.4.4.3 Validation Checks.

The ISO's stage one validation checks are performed automatically whenever Ancillary Services Schedules and bids are submitted. The ISO's stage two validation is performed automatically. A Scheduling Coordinator can also check whether its Ancillary Services Schedules and bids will pass the ISO's stage two validation by manually initiating validation of its Ancillary Services Schedules and bids, as described in the SP, at any time prior to the deadline for submission of Ancillary Services Schedules and bids. It is a Scheduling Coordinator's responsibility to perform such checks.

30.4.5 Validation of Energy Bids.

The ISO will check whether Energy Bids comply with the format requirements and will notify a Scheduling Coordinator if its bid does not so comply. A Scheduling Coordinator can check whether its Energy Bids will pass the ISO's validation by manually initiating validation of its Energy Bids at any time prior to the deadline for submission of Energy Bids. It is the Scheduling Coordinator's responsibility to perform such checks. Scheduling Coordinators must comply with the ISO Data Templates and Validation Rules document, which contains the validation criteria for Energy Bids.

30.4.6 Format and Validation of Operational Ramp Rates.

The submitted operational ramp rate expressed in megawatts per minute (MW/min) as a function of the operating level, expressed in megawatts (MW), must be a staircase function with up to nine segments defined by a set of 1 to 10 pairs, e.g., (50,1),(100,3),(200,2), (300,2). There is no monotonicity requirement for the operational ramp rate. The submitted operational ramp rate shall be validated as follows:

- The range of the submitted operational ramp rate must cover the entire capacity of the resource, from the minimum to the maximum operating capacity, as registered in the Master File for the relevant resource.
- The operating level entries must match exactly (in number, sequence, and value) the corresponding minimum and maximum operational ramp rate breakpoints, as registered in the Master File for the relevant resource.
- If a Scheduling Coordinator does not submit an operational ramp rate for a generating unit for a day, the ISO shall use the maximum ramp rate for each operating range set forth in the Master File as the ramp rate for that unit for that same operating range for that day.
- The last ramp rate entry shall be equal to the previous ramp rate entry and represent the maximum operating capacity of the resource as registered in the Master File. The resulting operational ramp rate segments must lie between the minimum and maximum operational ramp rates, as registered in the Master File.
- The submitted operational ramp rate must be the same for each hour of the Trading Day, i.e., the

operational ramp rate submitted for a given hour must be the same with the one(s) submitted earlier for previous hours in the same Trading Day.

- Outages that affect the submitted operational ramp rate must be due to physical constraints, reported in SLIC and are subject to ISO approval. All approved changes to the submitted operational ramp rate will be used in determination of Dispatch Instructions for the shorter period of the balance of the Trading Day or duration of reported Outage.
- For all ISO Dispatch Instructions of Reliability Must Run resources the operational ramp rate will be the ramp rate declared in the Reliability Must Run Contract Schedule A.

30.4.7 Format and Validation of Startup and Shutdown Times.

For a Generating Unit, the submitted startup time expressed in minutes (min) as a function of down time expressed in minutes (min) must be a staircase function with up to 10 segments defined by a set of 1 to 10 down time and startup time pairs. The startup time is the time required to start the resource if it is offline longer than the corresponding down time. The last segment will represent the time to start the unit from a cold start and will extend to infinity. The submitted startup time function shall be validated as follows:

- The first down time must be 0 min.
- The down time entries must match exactly (in number, sequence, and value) the corresponding down time breakpoints of the maximum startup time function, as registered in the Master File for the relevant resource.
- The startup time for each segment must not exceed the startup time of the corresponding segment of the maximum startup time function, as registered in the Master File for the relevant resource.
- The startup time function must be strictly monotonically increasing, i.e., the startup time must increase as down time increases.

For Curtailable Demand, a single shutdown time in minutes is the time required for the resource to shut down after receiving a Dispatch Instruction.

30.4.8 Format and Validation of Startup and Shutdown Costs.

For a Generating Unit, the submitted startup cost expressed in dollars (\$) as a function of down time expressed in minutes (min) must be a staircase function with up to 10 segments defined by a set of 1 to 10 down time and startup cost pairs. The startup cost is the cost incurred to start the resource if it is offline longer than the corresponding down time. The last segment will represent the cost to start the resource from cold startup and will extend to infinity. The submitted startup cost function shall be validated as follows:

- The first down time must be 0 min.
- The down time entries must match exactly (in number, sequence, and value) the corresponding down time breakpoints of the cost-based startup cost function, as registered in the Master File for the relevant resource.
- The startup cost for each segment must not be negative and must not exceed the startup cost of the corresponding segment of the cost-based startup cost function, as registered in the Master File for the relevant resource. For gas-fired resources, the cost-based startup cost function shall be derived from the startup fuel function, as registered in the Master File for the relevant resource, and the applicable gas price index as approved by FERC.
- The startup cost function must be strictly monotonically increasing, i.e., the startup cost must increase as down time increases.

For Curtailable Demand, a single shutdown cost in \$ is the cost incurred to shut down the resource after receiving a Dispatch Instruction. The submitted shutdown cost must not be negative.

30.4.9 Format and Validation of Minimum Load Costs.

For a Generating Unit, the submitted Minimum Load Cost expressed in dollars per hour (\$/hr) is the cost incurred for operating the unit at minimum load. The submitted Minimum Load Cost must not be negative and must not exceed the cost-based Minimum Load Cost, as registered in the Master File for the relevant resource. For gas-fired resources, the cost-based Minimum Load Cost shall

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

the bidders were not attempting to exercise market power.

30.6A.2 The ISO will, subject to any existing power purchase contracts of a Generating Unit, have the right at any time based upon ISO Controlled Grid technical analyses and studies to designate a Generating Unit as a Reliability Must-Run Unit. A Generating Unit so designated shall then be obligated to provide the ISO with its proposed rates for Reliability Must-Run Generation for negotiation with the ISO. Such rates shall be authorized by FERC or the Local Regulatory Authority, whichever authority is applicable.

30.6A.3 On a yearly basis, the ISO will carry out technical evaluations based upon historic patterns of the operation of the ISO Controlled Grid and the ISO's forecast requirements for maintaining the reliability of the ISO Controlled Grid in the next year. The ISO will then determine which Generating Units it requires to continue to be Reliability Must-Run Units, which Generating Units it no longer requires to be Reliability Must-Run Units and which Generating Units it requires to become the subject of a Reliability Must-Run Contract which had not previously been so contracted to the ISO. None of the Generating Units owned by Local Publicly Owned Electric Utilities are planned to be designated as Reliability Must-Run Units by the ISO as of the ISO Operations Date but are expected to be operated in such a way as to maintain the safe and reliable operation of the interconnected transmission system comprising the ISO Control Area. However, in the future, Local Publicly Owned Electric Utilities may contract with the ISO to provide Reliability Must-Run Generation.

30.6A.4 A *pro forma* of the Reliability Must-Run Contract is attached as Appendix G. From the ISO Operations Date all Reliability Must-Run Units will be placed under the "As Called" conditions, but the parties may, pursuant only to the terms of the Reliability Must-Run Contract, Transfer any such unit to one of the alternative forms of conditions under specific circumstances. The ISO will review the terms of the applicable forms of agreement applying to each Reliability Must-Run Unit to ensure that the ISO will procure Reliability Must-Run Generation from the cheapest available sources and to maintain System Reliability. The ISO shall give notice to terminate Reliability Must-Run Contracts that are no longer necessary or can be replaced by less expensive and/or more competitive sources for maintaining the reliability of the ISO Controlled Grid.

30.6.1.1 Reliability Must-Run Charge.

The ISO shall prepare and send to each Responsible Utility in accordance with Appendix N, Part J an ISO Invoice in respect to those costs incurred under each Reliability Must-Run Contract that are payable to the ISO by such Responsible Utility or payable by the ISO to such Responsible Utility pursuant to Section 30.6.1.2. The ISO Invoices shall reflect all reductions or credits required or allowed under or arising from the Reliability Must-Run Contract or under this Section 30.6.1.1. The ISO Invoice shall separately show the amounts due for services from each RMR Owner. Each Responsible Utility shall pay the amount due under each ISO Invoice by the due date specified in the ISO Invoice, in default of which interest shall become payable at the interest rate provided in the Reliability Must-Run Contract from the due date until the date on which the amount is paid in full. For each Reliability Must-Run Contract, the ISO shall establish two, segregated commercial bank accounts under the "Facility Trust Account" referred to in Appendix N, Part J and Article 9 of the Reliability Must-Run Contract. One commercial bank account, the "RMR Owner Facility Trust Account," shall be held in trust by the ISO for the RMR Owner. The other commercial bank account, the "Responsible Utility Facility Trust Account," shall be held in trust by the ISO for the Responsible Utility. Payments received by the ISO from the Responsible Utility in connection with the Reliability Must-Run Contract, including payments following termination of the Reliability Must-Run Contract, will be deposited into the RMR Owner Facility Trust Account and payments from the ISO to the RMR Owner will be withdrawn from such account, in accordance with Section 30.6.1.1, Article 9 of the Reliability Must-Run Contract and Appendix N, Part J. Any payments received by the ISO from the RMR Owner in connection with the Reliability Must-Run Contract will be deposited into the Responsible Utility Facility Trust Account. Any payments due to the Responsible Utility of funds received from the RMR Owner in connection with the Reliability Must-Run Contract will be withdrawn from the Responsible Utility Facility Trust Account, in accordance with this Section 30.6.1.1, Appendix N, Part J and Article 9 of the Reliability Must-run Contract. Neither the RMR Owner Facility Trust Account nor the Responsible Utility Trust Account shall have other funds commingled in it at any time. The ISO shall not modify this Section 30.6.1.1 or Appendix N, Part J as it applies to procedures for the billing, invoicing and payment of charges under Reliability Must-Run Contracts without the Responsible Utility's consent, provided, however, that no such consent shall be required with respect to any change in the method by

which costs incurred by the ISO under RMR Contracts are allocated to or among Responsible Utilities.

30.6.1.1.1 Except where the Responsible Utility is also the RMR Owner, the Responsible Utility's payment of the ISO Invoice shall be made without offset, recoupment or deduction of any kind whatsoever. Notwithstanding the foregoing, if the ISO fails to deduct an amount required to be deducted under Section 30.6.1.1.1.1, the Responsible Utility may deduct such amount from payment otherwise due under such ISO Invoice.

30.6.1.1.1.1 If the Responsible Utility disputes an ISO Invoice, Revised Estimated RMR Invoice, or Revised Adjusted RMR Invoice, or Final Invoice, it shall pay the ISO Invoice but may pay under protest and reserve its right to seek a refund, with interest, from the ISO. If resolution of the dispute results in an amount paid by the Responsible Utility under protest being due from the ISO to the Responsible Utility and from the RMR Owner to the ISO, and such amount was paid to the RMR Owner by the ISO, then such amount, with interest at the interest rate specified in the applicable Reliability Must-Run Contract from the date of payment until the date on which the amount is repaid in full, shall be refunded by the RMR Owner to the ISO and from the ISO to the Responsible Utility, pursuant to Article 9 of the Reliability Must-Run Contract and Appendix N, Part J, by the RMR Owner's inclusion of such refund amount in the appropriate invoice. If the RMR Owner does not include such refund amount (including interest) in the appropriate invoice, then such refund amount shall be deducted by the ISO from the next succeeding amounts otherwise due from the Responsible Utility to the ISO and from the next succeeding amounts otherwise due from the ISO to the RMR Owner with respect to the applicable Reliability Must-Run Contract or, if such Contract has terminated, such amount shall be refunded by the ISO to the Responsible Utility; provided, however, that if and to the extent that such resolution is based on an error or breach or default of the RMR Owner's obligations to the ISO under the Reliability Must-Run Contract, then such refund obligation shall extend only to amounts actually collected by the ISO from the RMR Owner as a result of such resolution. If resolution of the dispute requires the ISO, but not the RMR Owner, to pay the Responsible Utility, then such award shall be recovered from any applicable insurance proceeds, provided that to the extent sufficient funds are not recoverable through insurance, the amount of the award (whether determined through settlement, or ADR or otherwise) shall be collected by the ISO pursuant to Section 13.5, and in any event, the award shall be paid by the ISO to the Responsible Utility

pursuant to Section 13.5.

30.6.1.1.1.2 If the Responsible Utility disputes an ISO Invoice, a Revised Estimated Invoice, a Revised Adjusted RMR Invoice, or a Final Invoice, or part thereof, based in whole or in part on an alleged error by the RMR Owner or breach or default of the RMR Owner's obligations to the ISO under the Reliability Must-Run Contract, the Responsible Utility shall notify the ISO of such dispute within 12 months of its receipt of the applicable Revised Adjusted RMR Invoice or Final Invoice from the ISO, except that the Responsible Utility may also dispute a Revised Estimated RMR Invoice, Revised Adjusted RMR Invoice, or Final Invoice for the reasons set forth above in this Section 30.6.1.1.1.2, within 60 days from the issuance of a final report with respect to an audit of the RMR Owner's books and accounts allowed by a Reliability Must-Run Contract.

30.6.1.1.1.3 If the Responsible Utility disputes an ISO Invoice, a Revised Estimated RMR Invoice, a Revised Adjusted RMR Invoice, or a Final Invoice, based in whole or in part on an alleged error by the ISO or breach or default of the ISO's obligations to the Responsible Utility, the Responsible Utility shall notify the ISO of such dispute prior to the later to occur of (i) the date 12 months following the date on which the ISO submitted such invoice to the Responsible Utility for payment or (ii) the date 60 days following the date on which a final report is issued in connection with an operational audit, pursuant to Section 22.1.2.2, of the ISO's performance of its obligations to Responsible Utilities under this Section 30.6.1.1 conducted by an independent third party selected by the ISO Governing Board and covering the period to which such alleged dispute relates. The ISO or any Responsible Utility shall have the right to request, but not to require, that the ISO Governing Board arrange for such an operational audit at any time.

30.6.1.1.1.4 Notwithstanding Section 13 of this ISO Tariff, any Responsible Utility dispute relating to an ISO Invoice, a Revised Estimated Invoice, a Revised Adjusted Invoice, a Final Invoice, or a RMR Charge, RMR Payment or RMR Refund as defined in Appendix N, Part J, shall be resolved through the dispute resolution process specified in the relevant RMR Contract. If the Responsible Utility fails to notify the ISO of any dispute as provided above, it shall be deemed to have validated the invoice and waived its right to dispute such invoice.

30.6.1.1.2 The RMR Owner shall, to the extent set forth herein, be a third party beneficiary of, and have all rights that the ISO has under the ISO Tariff, at law, in equity or otherwise, to enforce the Responsible Utility's obligation to pay all sums invoiced to it in the ISO Invoices but not paid by the Responsible Utility, to the extent that, as a result of the Responsible Utility's failure to pay, the ISO does not Pay the RMR Owner on a timely basis amounts due under the Reliability Must-Run Contract. The RMR Owner's rights as a third party beneficiary shall be no greater than the ISO's rights and shall be subject to the dispute resolution process specified in the relevant RMR Contract. Either the ISO or the RMR Owner (but not both) will be entitled to enforce any claim arising from an unpaid ISO Invoice, and only one party will be a "disputing party" under the dispute resolution process specified in the relevant RMR Contract with respect to such claim so that the Responsible Utility will not be subject to duplicative claims or recoveries. The RMR Owner shall have the right to control the disposition of claims against the Responsible Utility for non-payments that result in payment defaults by the ISO under a Reliability Must-Run Contract. To that end, in the event of non-payment by the Responsible Utility of amounts due under the ISO Invoice, the ISO will not take any action to enforce its rights against the Responsible Utility unless the ISO is requested to do so by the RMR Owner. The ISO shall cooperate with the RMR Owner in a timely manner as necessary or appropriate to most fully effectuate the RMR Owner's rights related to such enforcement, including using its best efforts to enforce the Responsible Utility's payment obligations if, as, to the extent, and within the time frame, requested by the RMR Owner. The ISO shall intervene and participate where procedurally necessary to the assertion of a claim by the RMR Owner.

30.6.1.1.3 If a Responsible Utility first executed a TCA after April 1, 1998 (a "New Responsible Utility") and if:

- (i) the senior unsecured debt of the New Responsible Utility is rated or becomes rated at less than A- from Standard & Poor's ("S&P") or A3 from Moody's Investment Services ("Moody's"), and
- (ii) Such ratings do not improve to A- or better from S&P or A3 or better from Moody's within 60 days,

the New Responsible Utility shall issue and confirm to the ISO an irrevocable and unconditional letter of

credit in an amount equal to three times the highest monthly payment invoiced by the ISO to the New Responsible Utility (or the prior Responsible Utility) in connection with services under Reliability Must-Run Contracts in the last 3 months for which invoices have been issued. The letter of credit must be issued by a bank or other financial institution whose senior unsecured debt rating is not less than A from S&P and A2 from Moody's. The letter of credit shall be in such form as the ISO may reasonably require from time to time by notice to the New Responsible Utility and shall authorize the ISO or the Owner to draw on the letter of credit for deposit solely into the RMR Owner Facility Trust Account in an amount equal to any amount due and not paid by the Responsible Utility under the ISO Invoice. The security provided by the New Responsible Utility pursuant to this Section 30.6.1.1.3 is intended to cover the New Responsible Utility's outstanding liability for payments it is liable to make to the ISO under this Section 30.6.1.1, including monthly payments, any reimbursement for capital improvement, termination fees and any other payments to which the ISO is liable under Reliability Must-Run Contracts.

30.6.1.2 Responsibility for Reliability Must-Run Charge.

Except as otherwise provided in Section 30.6.1.2.1, the costs incurred by the ISO under each Reliability Must-Run Contract shall be payable to the ISO by the Responsible Utility in whose PTO Service Territory the Reliability Must-Run Generating Units covered by such Reliability Must-Run Contract are located or, where a Reliability Must-Run Generating Unit is located outside the PTO Service Territory of any Responsible Utility, by the Responsible Utility or Responsible Utilities whose PTO Service Territories are contiguous to the Service Area in which the Generating Unit is located, in proportion to the benefits that each such Responsible Utility receives, as determined by the ISO. Where costs incurred by the ISO under a Reliability Must-Run Contract are allocated among two or more Responsible Utilities pursuant to this section, the ISO will file the allocation under Section 205 of the Federal Power Act.

30.6.1.2.1 Responsibility for Reliability Must-Run Charges Associated with SONGS.

If the ISO procures Reliability Must-Run Generation from the San Onofre Nuclear Generation Station Units 2 or 3, it shall determine prior to the operation of such facilities as Reliability Must-Run Generation the appropriate allocation of associated charges, if any, among Responsible Utilities. The allocation of such charges shall be based on the reliability benefits that the ISO reasonably identifies through studies

and analysis as accruing to the respective Service Areas of the Responsible Utilities.

30.6.1.2.2 The ISO may Dispatch an RMR Unit that has currently selected Condition 2 of its RMR Contract to provide Energy through an out-of-market transaction for reasons other than to manage Intra-Zonal Congestion or to address local reliability under the following conditions:

- (1) The ISO projects that it will require Energy from the Condition 2 RMR Unit to (a) meet forecast Demand and operating reserve requirements or (b) manage Inter-Zonal Congestion;
- (2) If ISO must Dispatch a Condition 2 RMR Unit to meet forecast Demand and operating reserve requirements, the ISO must first revoke or deny waivers of the must-offer obligation from all other Generating Units, including non-Condition 2 RMR Units and Generating Units not subject to an RMR Contract subject to the must-offer obligation and not on outage, except as set forth in item (5) below;
- (3) If ISO must Dispatch a Condition 2 RMR Unit to manage projected Inter-Zonal Congestion, the ISO must first revoke or deny waivers of the must-offer obligation from all other Generating Units, including non-Condition 2 RMR Units and Generating Units not subject to an RMR Contract subject to the must-offer obligation, that are within the Congested Zone, except as set forth in item (5) below;
- (4) Before Dispatching a Condition 2 RMR Unit in accordance with this Section 30.6.1.2.2, the ISO must notify Market Participants of (a) the situation for which the ISO is contemplating Dispatching a Condition 2 RMR Unit in accordance with this Section 30.6.1.2.2, and (b) the date and time the ISO requires the Condition 2 RMR Unit so Dispatched to be operating. The ISO shall provide such notice as far in advance as practical and prior to directing the Condition 2 Unit to start up;
- (5) The ISO does not have to revoke or deny a waiver to a Generating Unit (a) subject to environmental limitations if doing so would violate such limitations, or cause the Generating Unit to be unavailable in the future, or if the environmental limitations currently restrict the

availability or use of the Generating Unit; or (b) if that Generating Unit would cause or exacerbate Congestion, Overgeneration or other operational problem; or (c) if that Generating Unit is incapable of being available for Dispatch in the required timeframe.

Notwithstanding anything to the contrary in the applicable RMR Contract, all MWh, start-ups and service hours provided by a Generating Unit that has currently selected Condition 2 of its RMR Contract pursuant to this Section 30.6.1.2.2 outside of the RMR Contract shall not be used to determine future RMR Contract Annual Service Limits. Payment for Dispatches pursuant to this Section 30.6.1.2.2 is governed by Section 11.2.4.2 of this Tariff.

30.6.1.3 Identification of Generating Units.

Each Generator shall provide data identifying each of its Generating Units and such information regarding the capacity and the operating characteristics of the Generating Unit as may be reasonably requested from time to time by the ISO.

31 DAY-AHEAD MARKET.

31.1 Timing of Day-Ahead Scheduling.

31.1A The ISO may in its sole discretion implement any temporary variation or waiver of the timing requirements of this Section 31.1 (including the omission of any step) if any of the following criteria are met:

- (i) such waiver or variation of timing requirements is reasonably necessary to preserve System Reliability, prevent an imminent or threatened System Emergency or to retain Operational Control over the ISO Controlled Grid during an actual System Emergency.
- (ii) the ISO receives Schedules that require delay in performing Day-Ahead Market or Hour-Ahead Market evaluations, such as in the case of the ISO receiving Inter-Scheduling Coordinator Energy Trades that do not balance;
- (iii) because of error or delay, the ISO requires additional time to fulfill its responsibilities pursuant to Section 30.1.3 of the ISO Tariff;

- (iv) problems with data or the processing of data cause a delay in receiving or issuing Schedules or publishing information on the WEnet;
- (v) problems with telecommunications or computing infrastructure cause a delay in receiving or issuing Schedules or publishing information on the WEnet;

If the ISO temporarily implements a waiver or variation of such timing requirements, the ISO will publish the following information on WEnet as soon as practicable:

- (i) the exact timing requirements affected;
- (ii) details of any substituted timing requirements;
- (iii) an estimate of the period for which this waiver or variation will apply;
- (iv) reasons for the temporary waiver or variation.

31.1A.1 If, despite the variation of any time requirement or the omission of any step, the ISO either fails to receive sufficient Schedules to operate the Day-Ahead Market or is unable to perform Congestion Management in the Day-Ahead Market, the ISO may abort the Day-Ahead Market and require all Schedules to be submitted, and Congestion Management to be performed, in the Hour-Ahead Market.

31.1A.2 If, despite the variation of any time requirement or omission of any step, the ISO either fails to receive sufficient Schedules to operate the Hour-Ahead Market or is unable to perform Congestion Management in the Hour-Ahead Market, the ISO may abort the Hour-Ahead Market and function in real time.

31.1.1 Reliability Must Run Information.

By no later than 5:00 a.m. on the day before the Trading Day, the ISO will notify Scheduling Coordinators for Reliability Must-Run Units of the amount and time of Energy requirements from specific Reliability Must-Run Units that the ISO requires to deliver Energy in the Trading Day to the extent that the ISO is aware of such requirements (the "RMR Dispatch Notice"). The Energy to be delivered for each hour of the Trading Day pursuant to the RMR Dispatch Notice (including Energy the RMR Owner is entitled to

substitute for Energy from the Reliability Must-Run Unit pursuant to the RMR Contract) shall be referred to as the "RMR Energy".

31.1.1.1 No later than 6:00 a.m. on the day before the Trading Day, any RMR Owner receiving an RMR Dispatch Notice as indicated in this Section 31.1.1.1 (the "Applicable RMR Owner") must notify the ISO through the RMR Owner's Scheduling Coordinator (the "Applicable RMR SC"), with regard to each hour of the Trading Day identified in the RMR Dispatch Notice whether it intends to satisfy its obligation to deliver RMR Energy (i) by delivering RMR Energy pursuant to a market transaction ("RMR Market Energy"), and receiving only market compensation therefore (the "RMR Market Option"), or (ii) by delivering RMR Energy as a contract transaction ("RMR Contract Energy"), and accepting payment under the relevant RMR Contract (the "RMR Contract Option"). If the Applicable RMR Owner so notifies the ISO by March 1, 2001, for calendar year 2001, and by January 1 of any subsequent calendar year, the RMR Owner may during that calendar year notify the ISO directly of its choice of payment option, rather than through the Applicable RMR Owner's Scheduling Coordinator. If the Applicable RMR Owner elects to provide notice of its choice of payment option directly, the ISO will not accept notice from the Applicable RMR Owner's Scheduling Coordinator during the relevant calendar year. Notwithstanding anything to the contrary in any RMR Contract, the Applicable RMR Owner may not elect to satisfy its obligation to deliver the RMR Energy specified in the RMR Dispatch Notice by delivering that RMR Energy pursuant to a transaction in the Real Time Market.

31.1.2 RMR Contract Option.

For each hour for which the Applicable RMR Owner elects the RMR Contract Option, the Scheduling Coordinator shall submit a Day-Ahead Energy Schedule that includes all RMR Contract Energy. Any RMR Contract Energy not Scheduled to forecast Demand or through Inter-Scheduling Coordinator Energy Trades shall be balanced by also Scheduling an additional quantity of Demand equal to the remaining amount of RMR Contract Energy at a Load Point specified by the ISO for each RMR Unit (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 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. The ISO shall post the list of RMR Contract Energy Load Points on the ISO Home Page and shall make any modifications to that list effective only 1) after providing at least five (5) days notice and 2) on the first day of a month. Whether or not the RMR Contract Energy is in the Final Schedule, the Applicable RMR Owner must deliver the RMR Contract Energy pursuant to the RMR Dispatch Notice. 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 Energy that is not scheduled as required by this Section 31.1.2. All RMR Energy delivered under this option shall be deemed delivered under a Nonmarket Transaction for the purposes of the RMR Contract. In the event that the RMR Contract Energy is not delivered for any hour, (i) if the RMR Contract Energy had been scheduled, the Applicable RMR Owner shall not be entitled to an Availability Payment under the RMR Contract and the Applicable RMR Scheduling Coordinator shall pay for the Imbalance Energy necessary to replace that RMR Energy; and (ii) if the RMR Contract Energy had not been scheduled, the Applicable RMR Owner shall not be entitled to an Availability Payment under the RMR Contract and, if the variable costs saved by the Owner's failure to deliver the RMR Contract Energy (which shall be equal to the Variable Cost Payment determined pursuant to Schedule C in the RMR Contract) are greater than the foregone Availability Payment under the RMR Contract, the Applicable RMR Owner shall pay the difference between the variable costs saved and the Availability Payment.

31.1.2.1 [Not Used]

31.1.3 RMR Market Option.

This Section 34.1.3 provides how an Applicable RMR Owner electing the RMR Market Option shall satisfy its obligation to deliver RMR Energy.

31.1.3.1 For each hour for which an Applicable RMR Owner has selected the Market Option, the Applicable RMR Owner (i) may bid into a power exchange market any amount of the RMR Market Energy and (ii) may schedule as a bilateral Day-Ahead transaction any amount of RMR Market Energy.

The Preferred Day-Ahead Schedule of the Applicable RMR Scheduling Coordinator shall include as RMR Market Energy for each hour the sum of the amount awarded to the Applicable RMR Owner in any power

exchange market for that hour and the amount scheduled as a bilateral Day-Ahead transaction for that hour. If the Preferred Day-Ahead Schedule of the Applicable RMR Scheduling Coordinator for any hour includes 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.

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. In the event that the RMR Market Energy is not delivered, (i) if the RMR Market Energy had been scheduled, the Applicable RMR Owner shall not be entitled to an Availability Payment under the RMR Contract and the Applicable RMR Scheduling Coordinator shall pay for the Imbalance Energy necessary to replace that RMR Market Energy, or (ii) if the RMR Market Energy had not been scheduled, the Applicable RMR Owner shall not be entitled to an Availability Payment under the RMR Contract and, if the variable costs saved by the Owner's failure to deliver the RMR Market Energy (which shall be equal to the Variable Cost Payment determined pursuant to Schedule C in the RMR Contract) are greater than the foregone Availability Payment under the RMR Contract, the Applicable RMR Owner shall pay the difference between the variable costs saved and the Availability Payment.

31.1.3.2 If the Applicable RMR Scheduling Coordinator's Preferred Day-Ahead Schedule does not include the entire amount of RMR Market Energy for any hour, the Applicable RMR Owner shall bid all remaining RMR Market Energy for that hour, net of any RMR Energy the Applicable RMR Owner elects to provide through an Hour-Ahead bilateral transaction for that hour, into the next available power exchange market for such hour at zero dollars per MWh.

31.1.3.2.1 The Applicable RMR Scheduling Coordinator's Preferred Hour-Ahead Schedule for each hour shall include all RMR Market Energy specified in the RMR Dispatch Notice for that hour, except for the amount of RMR Energy that the Applicable RMR Owner was required to bid into the power exchange markets under Section 31.1.3.2 but was not awarded in such power exchange markets for such hour. If the Preferred Hour-Ahead Schedule of the Applicable RMR Scheduling Coordinator for any hour includes

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 or MSS Service Area for which it will schedule deliveries for each of the Settlement Periods of the following Trading Day; however, the requirements of this Section shall not apply to (a) the portion of a Scheduling Coordinator's Demand associated with Station Power and (b) the Scheduling Coordinator's Demand within a UDC or MSS Service Area if the Scheduling Coordinator's maximum Demand within that UDC or MSS Service Area during the preceding twelve (12) months was less than one (1) megawatt, provided that this exemption shall not apply to any Scheduling Coordinator that did not submit Schedules for any metered Demand within a UDC or MSS Service Area over the preceding twelve (12) month period. The ISO shall aggregate the Demand information by UDC or MSS Service Area and transmit the aggregate Demand information to each UDC or MSS 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 (a) the portion of a Scheduling Coordinator's Demand associated with Station Power and (b) the Scheduling Coordinator's Demand within a UDC or MSS Service Area if the Scheduling Coordinator's Maximum

Demand within the UDC or MSS Service Area during the preceding twelve (12) months was less than one (1) megawatt, provided that this exemption shall not apply to any Scheduling Coordinator that did not submit Schedules for any metered Demand within a UDC or MSS Service Area over the preceding twelve (12) month period.

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

Scheduling Coordinators to determine the compatibility of such Preferred Schedules with the RMR Dispatch Notices. The ISO shall notify the Scheduling Coordinator of any specific Reliability Must-Run Units which have not been included in the Preferred Schedule but which the ISO requires to run in the next Trading Day. The ISO will also notify the Scheduling Coordinator of any Ancillary Services it requires from specific Reliability Must-Run Units under their Reliability Must-Run Contracts in the next Trading Day. If the ISO identifies mismatches in the scheduled quantity or location for any Inter-Scheduling Coordinator Energy Trade, it will notify the Scheduling Coordinators concerned and give them until a specified time, which will allow them approximately one half-hour, in which to modify their Schedules to resolve the mismatch before it applies the provisions of Section 30.2.3.4. The ISO shall analyze the combined Preferred Schedules submitted by all Scheduling Coordinators to forecast the probability of Congestion being caused by the Preferred Schedules. If the ISO finds that the Preferred Schedules will not cause Congestion, and subject to Section 30.2.3.4, the Preferred Schedules shall become the Final Schedules and the ISO shall notify Scheduling Coordinators accordingly.

31.1.8 Issuance of Suggested Adjusted Schedules.

If the ISO finds that the Preferred Schedules would cause Congestion, it shall issue Suggested Adjusted Schedules no later than 11:00 a.m. on the day preceding the Trading Day. The ISO will include in the Suggested Adjusted Schedules the resolution of any mismatches in Inter-Scheduling Coordinator Energy Trades, as determined by the ISO.

31.1.9 Submission of Revised Schedules.

If the ISO has issued Suggested Adjusted Schedules, by 12:00 noon on the day preceding the Trading Day, each Scheduling Coordinator may submit a Revised Schedule to the ISO or shall inform the ISO that it does not wish to make any change to its previously submitted Preferred Schedule. If the ISO identifies mismatches in the scheduled quantity or location for any Inter-Scheduling Coordinator Energy Trade, it will notify the Scheduling Coordinators concerned and give them until a specified time, which will allow them approximately one half-hour, in which to modify their Schedules to resolve the mismatch before it applies the provisions of Section 30.2.3.4.

31.1.9.1 Revised Schedules Become Final Day-Ahead Schedules.

Subsequent to receiving Revised Schedules if the ISO identifies no Congestion on the ISO Controlled Grid and subject to Section 30.2.3.4, the Revised Schedules and any unamended Preferred Schedules shall become Final Day-Ahead Schedules and the ISO shall notify Scheduling Coordinators accordingly.

31.1.9.2 Use of Congestion Management for Final Schedule.

Subsequent to receiving Revised Schedules if the ISO identifies Congestion on the ISO Controlled Grid, it shall use the Congestion Management provisions of this ISO Tariff to develop the Final Day-Ahead Schedules.

32 [Not Used]

33 HOUR AHEAD.

33.1 Timing of Hour-Ahead Scheduling.

33.1.1. Submission of Preferred Schedule.

Each Scheduling Coordinator's Preferred Schedule for each Settlement Period during a Trading Day together with any additional or updated Adjustment Bids or Ancillary Services bids shall be submitted at least two hours and fifteen minutes (i.e., 135 minutes) prior to the commencement of that Settlement Period.

33.1.1.1 Statements in Preferred Schedule.

In submitting its Preferred Schedule, each Scheduling Coordinator may submit Adjustment Bids for use in the Hour-Ahead Market to assist in relieving Congestion.

33.1.1.2 Final Hour-Ahead Schedule Submission.

Each Hour-Ahead Schedule shall indicate the changes which the relevant Scheduling Coordinator wishes to make to the Final Day-Ahead Schedule.

33.1.2 ISO Analysis of Preferred Schedules.

The ISO shall analyze the combined Preferred Schedules submitted by all Scheduling Coordinators to forecast the probability of Congestion being caused by the Preferred Schedules.

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.

34.1.2.1.1 Frequently Mitigated Adders

Generating Units of Participating Generators for which the ISO denies a must-offer waiver request and for which only a portion of their capacity is Eligible Capacity, as well as self-scheduled Generating Units of Participating Generators that have Eligible Capacity, that submit Supplemental Energy bids that are mitigated under Section 3.2.2.2 of Appendix P five times in a single Trading Day, based on five-minute dispatch periods, shall receive a supplemental payment adder ("Frequently Mitigated Adder") for the Dispatched Energy that is mitigated for each mitigated interval in that Trading Day beginning with the 10-minute settlement interval of the fifth mitigation and continuing for each following 10-minute settlement interval through the remainder of the Trading Day, provided that the Frequently Mitigated Adder plus the Mitigated Price does not exceed the resources' original Supplemental Bid. The Frequently Mitigated Adder shall be \$40 per megawatt hour multiplied by the ratio of the Eligible Capacity (excluding any portion of minimum load capacity that is not also Resource Adequacy, RMR or designated under **TCPM**) to the total Qualifying Capacity (excluding minimum load level) of the Generating Unit. Generating Units shall not receive Frequently Mitigated Adders in connection with decremental dispatches.

The total amount of Frequently Mitigated Adders that any Generating Unit can receive in a Trading Day shall not exceed the Must-Offer Capacity Payment that the Generating Unit would have received pursuant to Section 40.14 if the ISO had denied a must-offer waiver denial request. Further, Frequently Mitigated

Adders will stop accruing in any calendar month once the combined value for that month of Frequently Mitigated Adders, Must-Offer Capacity Payments and minimum load imbalance energy payments under Section 40.8.3 reaches the level of the Monthly TCPM Charge (established in Schedule 6 of Appendix F) reduced by the PER (established in Schedule 6 of Appendix F) for that month multiplied by the megawatts of Eligible Capacity of that Generating Unit. This Section 34.1.2.1.1 shall expire at midnight on the day before the MRTU Tariff goes into effect.

34.1.2.1.2 Allocation of Frequently Mitigated Adder Costs

Costs incurred under Section 34.1.2.1.1 will be allocated in accordance with Section 27.1.3.

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.

A Physical Scheduling Plant shall be treated as a single Generating Unit for Supplemental Energy bid purposes.

34.2.1.3 Demand 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 Demand for each Settlement Period:

- (a) Scheduling Coordinator's ID code;
- (b) name of Demand;
- (c) Demand shutdown time in minutes;
- (d) Demand shutdown cost in \$/start;
- (e) Demand minimum curtailed load cost in \$/hr; and
- (f) the MW and \$/MWh values for each Demand for which a Supplemental Energy bid is being submitted consistent with this ISO Tariff.

34.2.1.4 External Import 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 external import for each Settlement Period:

- (a) Scheduling Coordinator's ID code;
- (b) name of Scheduling Point;
- (c) interchange ID (the name of the selling entity, the buying entity, and a numeric identifier);
- (d) external Control Area ID;
- (e) Schedule ID (NERC ID number);
- (f) complete WECC tag;

- (g) operational ramp rate (MW/minute);
- (h) the MW and \$/MWh values for each external import for which a Supplemental Energy bid is being submitted consistent with this ISO Tariff;
- (i) minimum block of hours that bid must be dispatched; \
- (j) Flag indicating the bid must is capable available for intra-hour Redispatch. If this flag is set to no then the bid is indicating that the bid must be pre-dispatched and not re-dispatched during the real-time operating hour;
- (k) interchange ID code;
- (l) external Control Area ID;
- (m) Schedule ID (NERC ID number) and complete WECC tag;
- (n) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;
and
- (o) the contract reference number, if applicable.

34.2.1.4A Format of Energy Bids.

The Scheduling Coordinator's Final Hour-Ahead Schedule for each resource must be within the range of the Energy Bids. The minimum MW output level specified for a resource, which may be zero MW (or negative for pumped storage resources), and the maximum MW output level specified for a resource must be physically achievable by the resource. All submitted Energy Bids must be in the form of a monotonically increasing staircase function for Demands. These staircase functions will be composed of up to eleven (11) ordered pairs (i.e., ten (10) steps or price bands) of quantity/price information, with an operational ramp rate associated with the entire MW range as provided for in this ISO Tariff. Scheduling Coordinators must comply with the ISO Data Templates and Validation Rules document, which contains the format for submission of Energy Bids.

34.2.1.4B Real Time Operational Activities in the Hour Prior to the Settlement Period.

34.2.1.5 Schedule Confirmation.

In the hour prior to the beginning of the Settlement Period, the ISO will review and evaluate the current system operating conditions to ensure sufficient Energy and Ancillary Services resources are available for the next Settlement Period. The ISO will:

- (a) verify that each Scheduling Coordinator's Ancillary Services obligations are scheduled as required. The ISO will procure additional Ancillary Services if insufficient resources are scheduled;
- (b) verify any Supplemental Energy bids received up to thirty (30) minutes prior to the Settlement Period, for increases or decreases in Energy output which it may require for the Settlement Period; and
- (c) verify that with currently anticipated operating conditions there is sufficient transfer capacity on the ISO Controlled Grid to implement all Final Schedules.

34.2.1.6 Confirm Interchange Transaction Schedules (ITSs).

Also in the hour prior to the beginning of the Settlement Period the ISO will:

- (a) adjust interchange transaction schedules (ITSs) as required under Existing Contracts in accordance with the procedures in the ISO Tariff for the management of Existing Contracts;
- (b) adjust ITSs as required by changes in transfer capability of transmission paths occurring after close of the Hour-Ahead Market; and
- (c) agree on ITS changes with adjacent Control Area Operators.

34.3 Real-Time Dispatch.

The ISO, using RTD Software, shall economically Dispatch each Generating Unit, Curtailable Demand, System Unit, Interconnection schedule or System Resource that is effective to: (i) meet Imbalance Energy requirements and eliminate any Price Overlap in real time, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 34.3.0.3, and (ii) relieve Congestion, if

necessary, to ensure System Reliability and to maintain Reliability Criteria. The ISO shall determine that additional output is needed if the current output levels of the Regulation Generating Units, System Units, and System Resources deviate from their preferred operating points by more than a specified threshold (to be determined by the ISO), or to meet the projected Imbalance Energy requirements for the next Dispatch Interval. The ISO shall employ a multi-interval constrained optimization methodology (RTD Software) to calculate an optimal dispatch for each Dispatch Interval within a time horizon that shall extend to the end of the next hour. The ISO shall Dispatch resources that have submitted Energy Bids over the time horizon to meet forecasted Imbalance Energy requirements minimizing the Imbalance Energy procurement cost over the entire time horizon, subject to resource and transmission system constraints. However, Dispatch Instructions shall be issued for the next Dispatch Interval only. The ISO also shall instruct resources to start up or shut down over the time horizon based on their submitted and validated Start-Up Fuel Costs, Minimum Load Costs and Energy Bids *and, in addition to these costs, the optimization shall also include for FERC Must-Offer Generators, 1/8th of the applicable Monthly TCPM Charge and the Generating Unit's first bid price segment to represent its minimum load Energy payment.* These resources shall receive binding start-up or shut-down pre-dispatch instructions as required by their startup time. The ISO shall only start resources that can start within the time horizon. The ISO may shut down resources that do not need to be on-line if constraints within the time horizon permit. However, resources providing Regulation or Spinning Reserve shall not be shut down. On-line resources providing Non-Spinning or Replacement Reserve shall also not be eligible for shutdown, unless their minimum down time does not exceed 10 minutes.

34.3.0 Rules For Real-Time Dispatch of Imbalance Energy Resources.

34.3.0.1.1 Overview.

During real time, the ISO shall dispatch Generating Units, Loads and System Resources to procure Imbalance Energy. In addition, the ISO may also need to purchase additional Ancillary Services if the services arranged in advance are used to provide Imbalance Energy, and such depletion needs to be recovered to meet reliability contingency requirements.

34.3.0.1.2 Utilization of the Energy Bids.

The ISO will use the Energy Bids to Dispatch Supplemental Energy and Ancillary Services to procure balancing Energy for:

- (a) satisfying needs for Imbalance Energy;
- (b) mitigating Inter-Zonal Congestion;
- (c) allowing resources providing Regulation service to return to the preferred operating point within their regulating ranges;
- (d) allowing recovery of Operating Reserves utilized in real-time operations;
- (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 using Energy Bids Dispatched out of sequence.

34.3.0.2 General Principles.

The ISO shall base real-time Dispatch of Generating Units, Curtailable Demands, Interconnection schedules, System Units, Loads and System Resources on the following principles:

- (a) the ISO shall dispatch Generating Units, System Units, Dispatchable Interconnection schedules, and System Resources providing Regulation service to meet NERC and WECC Area Control Error (ACE) performance requirements;
- (b) in each Dispatch Interval, following the loss of a resource and once ACE has returned to zero, the ISO shall determine whether the Regulation Generating Units, System Units, Dispatchable Interconnection schedules, and System Resources are operating at a point away from their preferred operating point and project the Imbalance Energy requirements based on the forecasted Demand for the next Dispatch Interval. The ISO shall then Dispatch Generating Units, System Units, Curtailable Demands, Dispatchable Interconnection schedules, and System Resources available (either providing Spinning Reserve, Non-Spinning Reserve, Replacement Reserve or offering Supplemental Energy) to meet the projected Imbalance Energy requirements for the next Dispatch

- Interval and return the Regulation Generating Units, System Units, Dispatchable Interconnection schedules, and System Resources to their preferred operating points to restore their full regulating margin;
- (c) the ISO shall economically Dispatch Generating Units, System Units, Loads, Curtailable Demands, Dispatchable Interconnection schedules and System Resources only to meet its Imbalance Energy requirements and eliminate any Price Overlap between Energy Bids subject to resource and transmission system Constraints, thereby, Dispatching the relevant resources in real time for economic trades either between Scheduling Coordinators or within a Scheduling Coordinator's portfolio;
- (d) subject to Section 34.3.0.3 and its subparts, the ISO shall select the Generating Units, System Units, Loads, Curtailable Demands, Dispatchable Interconnection schedules and System Resources to be dispatched in merit order according to their Energy Bids to meet its Imbalance Energy requirements and to eliminate any Price Overlap based on a constrained optimization method to minimize the overall cost of Imbalance Energy subject to resource and transmission system Constraints;
- (e) subject to Section 34.3.0.3 and its subparts, the ISO shall not discriminate between Generating Units, System Units, Loads, Curtailable Demands, Dispatchable Interconnection schedules and System Resources other than based on price, and the effectiveness (e.g., location and ramp rate) of the resource concerned to respond to the fluctuation in Demand or Generation or to resolve Inter-Zonal Congestion;
- (f) Generating Units, System Units, Loads, Curtailable Demands, Dispatchable Interconnection schedules and System Resources shall be dispatched during the operating hour only until the next variation in Demand or the end of the operating hour, whichever is sooner. In dispatching such resources, the ISO makes no further commitment as to the duration of their operation, nor the level of their output or Demand, except to the extent that a Dispatch instruction causes Energy to be delivered in a different Dispatch Interval. In Dispatching such resources, the ISO may make

commitments beyond the current Settlement Period;

- (g) The ISO will not differentiate between Ancillary Services procured by the ISO and Ancillary Services which are being self-provided;
- (h) The operational ramp rate(s) of a resource will be considered by the RTD Software in determining the amount of Instructed Imbalance Energy by Dispatch Interval, and such consideration may result in Instructed Imbalance Energy in Dispatch Intervals prior to or subsequent to the Dispatch Interval to which the Dispatch Instruction applies;
- (i) System Resources identified as Dispatchable within the operating hour pursuant to Section 34.2.1.1A shall be Dispatched optimally through the RTD Software. Such bids will be settled pursuant to Section 11.2.4.1.1.2;
- (j) The ISO will pre-dispatch Energy Bids from System Resources, subject to Hourly Pre-Dispatch as indicated in Section 34.2.1.1A, prior to the beginning of each hour consistent with applicable WECC interchange scheduling practices, assuring that any Price Overlap between such decremental and incremental Energy Bids will be eliminated. Such bids will be settled pursuant to Section 11.2.4.1.1.2.
- (k) In issuing the Dispatch Instructions, the ISO will not intentionally request UDCs, Participating Generators, Generating Unit operators, Participating Transmission Owners, Control Area Operators (to the extent the agreement between the Control Area Operator and the ISO so provides), Metered Subsystem Operators or Scheduling Coordinators to exceed any inherent plant rating or local restriction imposed by the plant or transmission owner in order to protect the design and/or operational integrity of its plant or equipment. In issuing Dispatch Instructions to PTOs, the ISO will comply with Section 5.1.7 of the TCA. Any conflict that may arise between an ISO issued Dispatch Instruction and a plant or transmission owner's restriction as mentioned above must be immediately brought to the ISO's attention by the person receiving such Dispatch Instruction prior to any attempt to implement that Dispatch Instruction.

34.3.0.3 Ancillary Services Dispatch.

The ISO will base its standards for the Dispatch of Ancillary Services upon WECC, MORC, and ISO Controlled Grid reliability requirements. The ISO may Dispatch Generating Units, Loads, System Units and System Resources contracted to provide Ancillary Services (either procured through the ISO's competitive market, or self-provided by Scheduling Coordinators) to supply Imbalance Energy. During normal operating conditions, the ISO shall Dispatch the following resources to supply Imbalance Energy: (i) those Generating Units, Loads, System Units and System Resources having offered Supplemental Energy bids, (ii) those Generating Units, Loads, System Units and System Resources contracted to provide Replacement Reserve and (iii) those Generating Units, Loads, System Units and System Resources that have contracted to provide Spinning and Non-Spinning Reserve, except for those resources that have indicated that the capacity reserved would be 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 a threatened or actual System Emergency, the ISO may also Dispatch all other Generating Units, Loads, System Units and System Resources contracted to provide Spinning Reserve or Non-Spinning Reserve to supply Imbalance Energy. If a Generating Unit, Load, System Unit or System Resource, which is supplying Operating Reserve, is Dispatched to provide Imbalance Energy, the ISO shall replace the Operating Reserve from the same or another resource within the time frame specified in the WECC guidelines.

34.3.0.3.1 Dispatch of Competitively Procured and Self-Provided Ancillary Services.

Generating Units and Loads selected in the ISO competitive auction or self-provided shall be Dispatched based on their Energy Bids as described in Section 34.3.0.1.2, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 34.3.0.3.

34.3.0.3.2 Dispatch of Self-Provided Ancillary Services.

Where a Scheduling Coordinator has chosen to self-provide the whole of the additional Operating Reserve required to cover any Interruptible Imports which it has scheduled and has identified specific Generating Units, Loads, System Units or System Resources as the providers of the additional Operating Reserve concerned, the ISO shall Dispatch only the designated Generating Units, Loads, System Units or

System Resources in the event of the ISO being notified that the Interruptible Import is being curtailed. For all other Ancillary Services which are being self-provided the Energy Bid shall be used to determine the Dispatch, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 34.3.0.3.

34.3.0.3.3 Ancillary Services Requirements for Real Time Dispatch.

The following requirements apply to the Dispatch of Ancillary Services in real time:

34.3.0.3.3.1 Regulation.

- (a) Regulation provided from Generating Units or System Resources must meet the standards specified in this Tariff and the Part of A of Appendix K;
- (b) the ISO will Dispatch Regulation in merit order of Energy bid prices as determined by the EMS;
- (c) in the event of an unscheduled increase in system Demand or a shortfall in Generation output and Regulation margin drops below a predetermined value, the ISO will use scheduled Operating Reserve, Replacement Reserve or Supplemental Energy to restore Regulation margin; and
- (d) when scheduled Operating Reserve is used for restoration of Regulation reserve, the ISO shall arrange for the replacement of that Operating Reserve (see Section 34.3.0.3.3.4);

34.3.0.3.3.2 Operating Reserve.

- (a) Spinning Reserve:
 - (i) Spinning Reserve provided from Generating Units and Interconnection schedules must meet the standards specified in Part B of Appendix K;
 - (ii) the ISO will Dispatch Spinning Reserve as may be required to meet the Applicable Reliability Criteria;
 - (iii) the ISO may Dispatch Spinning Reserve as balancing Energy to return Regulation

Generating Units to their Set Points and restore full Regulation margin; and

- (iv) the ISO will Dispatch Spinning Reserve in merit order of Energy bid prices as determined by the RTD Software;
- (b) Non-Spinning Reserve:
- (i) Non-Spinning Reserve provided from Generating Units, Demands, and external imports of System Resources must meet the standards specified in Part C of Appendix K
 - (ii) the ISO may Dispatch Non-Spinning Reserve in place of Spinning Reserve to meet Applicable Reliability Criteria;
 - (iii) the ISO will Dispatch Non-Spinning Reserve in merit order of Energy bid prices as determined by the RTD Software; and
 - (iv) the ISO may Dispatch Non-Spinning Reserve to replace Spinning Reserve if there is a shortfall in Spinning Reserve because of a deficiency of balancing Energy;

34.3.0.3.3.3 Replacement Reserve.

- (a) Replacement Reserve provided from Generating Units, Curtailable Demands and Interconnection schedules must meet the standards specified in Part D of Appendix K
- (b) the ISO will utilize Replacement Reserve to replace Operating Reserve that has been Dispatched due to a shortfall in Generation or an increase in Demand;
- (c) the ISO may Dispatch Replacement Reserve to replace Operating Reserve that has been Dispatched for balancing Energy; and
- (d) the ISO will Dispatch Replacement Reserve in merit order of Energy Bid prices as determined by RTD;

34.3.0.3.3.4 Replacement of Operating Reserve.

- (a) in the event of an un-forecasted increase in system Demand or a shortfall in Generation output, the ISO shall utilize Replacement Reserve to restore Operating Reserve;
- (b) if pre-arranged Operating Reserve is used to meet balancing Energy requirements, the ISO may replace such Operating Reserve by Dispatch of additional balancing Energy available from Supplemental Energy bids;
- (c) any additional Operating Reserve needs may also be met the same way;
- (d) where the ISO elects to rely upon Supplemental Energy bids, the ISO shall select the resources with the lowest incremental Energy Bid price as established by RTD; and
- (e) if the ISO restores Operating Reserve through utilization of Replacement Reserve, the ISO is not required to replace the utilized Replacement Reserve;

34.3.0.3.3.5 Voltage Support.

- (a) Voltage Support provided from Generating Units shall meet the standards specified in this Tariff and the Part E of Appendix K;
- (b) the ISO may Dispatch Generating Units to increase or decrease MVar output within the power factor limits of 0.9 lagging to 0.95 leading (or within other limits specified by the ISO in any exemption granted pursuant to Section 8.2.3.4 of the ISO Tariff) at no cost to the ISO when required for System Reliability;
- (c) may Dispatch each Generating Unit to increase or decrease MVar output outside of established power factor limits, but within the range of the Generating Unit's capability curve, at a price calculated in accordance with ISO Tariff;
- (d) If Voltage Support is required in addition to that provided pursuant to 34.3.0.3.3.5 (b) and (c), the ISO will reduce output of Participating Generators certified in accordance with Appendix K . The ISO will select Participating Generators in the vicinity where such additional Voltage Support is required; and

- (e) the ISO will monitor voltage levels at Interconnections to maintain them in accordance with the applicable Inter-Control Area Agreements.

34.3.1 Resource Constraints.

The RTD Software shall enforce the following resource physical constraints:

- (a) Minimum and maximum operating resource limits. Outages and limitations due to transmission clearances shall be reflected in these limits. The more restrictive operating or regulating limit shall be used for resources providing Regulation so that the RTD Software shall not Dispatch them outside their regulating range.
- (b) Forbidden Operating Regions. Resources can only be ramped through these regions. The RTD Software shall not Dispatch resources within their Forbidden Operating Regions unless at the maximum applicable ramp rate to clear the Forbidden Operating Region in consecutive Dispatch Intervals.
- (c) Operational ramp rates and start-up times. The submitted operational ramp rate as provided for in Section 30.4.6 shall be used for all Dispatch Instructions. Each Energy Bid shall be Dispatched only up to the amount of Imbalance Energy that can be provided within the Dispatch Interval based on the applicable operational ramp rate. The Dispatch Instruction shall consider the relevant start-up time as provided for in Section 30.4.6, if the resource is off-line, the relevant ramp rate function, and any prior commitments such as schedule changes across hours and previous Dispatch Instructions. The start-up time shall be determined from the start-up time function and when the resource was last shut down. The start-up time shall not apply if the corresponding resource is on-line or expected to start.
- (d) Maximum number of daily start-ups. The RTD Software shall not cause a resource to exceed its daily maximum number of start-ups.
- (e) Minimum up and down time. The RTD Software shall not start up off-line resources before their minimum down time expires and shall not shut down on-line resources before

their minimum up time expires.

- (f) Operating (Spinning and Non-Spinning) Reserve. The RTD Software shall Dispatch Spinning and Non-Spinning Reserve subject to the limitations set forth in Section 34.3.0.3.
- (g) Hourly Pre-Dispatch. If Dispatched, each System Resource flagged for Hourly Pre-Dispatch in the next hour shall be Dispatched to operate at a constant level over the entire hour. The RTD Software shall perform the Hourly Pre-Dispatch for each hour once prior to the operating hour. Hourly Pre-Dispatched System Resources shall be Pre-Dispatched in merit order and shall not set the price. The Hourly Pre-Dispatch shall not subsequently be revised by the RTD Software.

34.3.2 Transmission System Constraints.

RTD shall use a Zonal DC network model where all nodes within a Zone would be collapsed into a single equivalent "Zonal bus." The constraints using the Zonal network model shall be the following:

- (a) Power balance constraint in each Zone. The system Imbalance Energy requirement shall be calculated on a Zonal basis. The power balance constraints shall dictate an optimal Dispatch that would eliminate the Imbalance Energy requirement in all Zones, subject to (b) below.
- (b) Inter-Zonal Interface constraints. These constraints shall limit the net active power flow on Inter-Zonal Interfaces at or below their transfer limits. For Inter-Zonal Interfaces between the ISO Control Area and another Control Area, inter-Zonal transfer capacity shall be reserved for awarded Ancillary Services from System Resources not already Dispatched.

34.3.2.1 Inter-Zonal Congestion.

If there is Inter-Zonal Congestion in real time, the ISO's RTD Software shall increase Generation and/or reduce Demand separately for each Zone to optimally Dispatch available resources to resolve the Congestion.

34.3.2.2 Selection of Generating Unit or Load to Increase Generation or Reduce Demand.

Where the ISO determines that it is necessary to increase Generation or reduce Demand in a Zone in order to relieve Inter-Zonal Congestion the ISO shall select in merit order, the Generating Unit within the Zone (or the Interconnection schedule in a Control Area adjacent to the Zone) with a non-zero capacity remaining to increment which has the lowest incremental bid price (\$/MWh) or the Curtailable Demand located within the Zone (or the Interconnection schedule in a Control Area adjacent to the Zone) with a non-zero capacity remaining to reduce which has the lowest Demand reduction bid price.

34.3.2.3 Selection of Generating Unit to Reduce Generation.

Where the ISO determines that it is necessary to reduce Generation in a Zone in order to relieve Inter-Zonal Congestion, the ISO shall select in merit order the Generating Unit within the Zone with a non-zero capacity remaining to decrement which has the highest decremental bid price.

34.3.2.4 Inter-hour Dispatch of Resources Without Real-Time Energy Bids.

Real-time Dispatch Instructions shall be issued for each Dispatch Interval as needed to prescribe the ramp between a resource's Final Hour-Ahead Schedule in one hour to its Final Hour-Ahead Schedule in the immediately succeeding operating hour. Such Dispatch Instructions shall be based on the lesser of: (1) the applicable operational ramp rate as provided for in Section 30.4.6 and (2) the ramp rate associated with the Standard Ramp. The Dispatch Instructions for ramping of Generating Units without real-time Energy Bids in both operating hours shall begin 10 minutes prior to the start of each operating hour and shall end no sooner than 10 minutes after and no later than 50 minutes after the start of each operating hour. Energy resulting from the Standard Ramp shall be deemed Standard Ramping Energy and will be settled in accordance with Appendix N, Part D-1, Section 2.1.2. Energy resulting from any ramp extending beyond the Standard Ramp will be deemed Ramping Energy Deviation and will be settled in accordance with Appendix N, Part D-1, Section 2.1.2.

34.3.2.5 Inter-hour Dispatch of Resources With Real-Time Energy Bids.

Real-time Dispatch Instructions associated with the ramp between a resource's Final Hour-Ahead Schedule in one hour to its Final Hour-Ahead Schedule in the immediately succeeding operating hour

shall be determined optimally by the RTD Software if the ISO has bids for either or both relevant operating hours. For any operating hour(s) for which bids have been submitted Dispatch Instructions will be optimized such that the Dispatch Operating Point is within the bid range(s). For any operating hour without submitted bids Dispatch Instructions will be optimized such that the Dispatch Operating Point conforms to the schedule within the operating hour. Energy resulting from the Standard Ramp shall be deemed Standard Ramping Energy and will be settled in accordance with Appendix N, Part D-1, Section 2.1.2. Energy resulting from any ramp extending beyond the Standard Ramp will be deemed Ramping Energy Deviation and will be settled in accordance with Appendix N, Part D-1, Section 2.1.2. Energy delivered or consumed as a result of ISO Dispatch of a resource's Energy Bid in one operating hour to a Dispatch Operating Point such that the resource cannot return to its successive operating hour Final Hour-Ahead Schedule by the beginning of the next operating hour is Residual Energy and shall be settled as Instructed Imbalance Energy as provided for in Appendix N, Part D-1, Section 2.1.2 and also may be eligible for recovery of its applicable Energy Bid costs in accordance with Section 11.2.4.1.1.1. Similarly, Energy delivered or consumed as a result of ISO Dispatch of a resource's Energy Bid in a future operating hour to a Dispatch Operating Point different from its current operating hour Final Hour-Ahead Schedule prior to the end of the current operating hour is also considered Residual Energy and shall be settled as Instructed Imbalance Energy as provided for in Appendix N, Part D-1, Section 2.1.2 and also may be eligible for recovery of its applicable Energy Bid costs in accordance with Section 11.2.4.1.1.1. When Ramping Energy Deviation and Residual Energy coexist within a given Dispatch Interval, the Ramping Energy Deviation shall be the portion of Instructed Imbalance Energy that is produced or consumed within the schedule-change band defined by the Final Hour-Ahead Schedules of the two consecutive Settlement Periods; the Residual Energy shall be the portion of Instructed Imbalance Energy that is produced or consumed outside the schedule-change band.

34.3.3 Inter-Zonal Congestion.

In the event of Inter-Zonal Congestion in real time, the ISO shall procure Imbalance Energy as described in Section 34.3.

34.3.4 Intra-Zonal Congestion.

Except as provided in Section 30.6.1, in the event of Intra-Zonal Congestion in real time, the ISO shall adjust resources in accordance with Sections 27.1.1.6.1 and 27.1.1.6.2.

34.3.5 Recovery of Operating Reserve.

If procured Operating Reserve is used to meet Imbalance Energy requirements, such Operating Reserve may be recovered by the ISO's replacing the associated Imbalance Energy through the Dispatch of other Energy Bids in merit order to allow the resources that were providing Energy from the procured Operating Reserve to return to their operating point before the provided the Energy from the Operating Reserves.

Any additional real-time Operating Reserve needs may be met through unloaded capacity from RMR resources.

34.3.6 Dispatch Information and Instructions.

34.3.6.1 Dispatch Information To Be Supplied to the ISO.

34.3.6.2 Dispatch Information To Be Supplied by Scheduling Coordinator

Each Scheduling Coordinator shall be responsible for the scheduling and Dispatch of Generation and Demand in accordance with its Final Schedule. Each Scheduling Coordinator shall keep the ISO apprised of any change or potential change in the current status of all Generating Units, Interconnection schedules and Inter-Scheduling Coordinator Energy Trades. This will include any changes in Generating Unit capacity that could affect planned Dispatch and conditions that could affect the reliability of a Generating Unit. Each Scheduling Coordinator shall immediately pass to the ISO any information which it receives from a Generator which the Generator provides to the Scheduling Coordinator pursuant to Section 34.5. Each Scheduling Coordinator shall immediately pass to the ISO any information it receives from a MSS Operator which the MSS Operator provides to the Scheduling Coordinator regarding any change or potential change in the current status of all Generating Units, System Units, Interconnection schedules and Inter-Scheduling Coordinator Energy Trades. This information includes any changes in MSS System Units and MSS Generating Unit capacity that could affect planned Dispatch and conditions that could affect the reliability of the System Unit or Generating Unit.

34.3.6.3 Dispatch Information To Be Supplied by UDCs.

Each UDC shall keep the ISO informed of any change or potential change in the status of its transmission lines and station equipment at the point of interconnection with the ISO Controlled Grid. Each UDC shall keep the ISO informed as to any event or circumstance in the UDC's service territory that could affect the reliability of the ISO Controlled Grid. This would include adverse weather conditions, fires, bomb threats, etc.

34.3.6.4 Dispatch Information To Be Supplied by PTOs.

Each PTO shall report any change or potential change in equipment status of the PTO's transmission assets turned over to the control of the ISO or in equipment that affects transmission assets turned over to the control of the ISO immediately to the ISO (this will include line and station equipment, line protection, Remedial Action Schemes and communication problems, etc.). Each PTO shall also keep the ISO immediately informed as to any change or potential change in the PTO's transmission system that could affect the reliability of the ISO Controlled Grid. This would include adverse weather conditions, fires, bomb threats, etc.

Each PTO shall schedule all Outages of its lines and station equipment which are under the Operational Control of the ISO in accordance with the appropriate procedures in Section 9.3. Each PTO shall coordinate any requests for or responses to Forced Outages on its transmission lines or station equipment which are under the Operational Control of the ISO directly with the appropriate ISO Control Center as defined in Section 7.2.4.1.

34.3.6.6 Dispatch Information To Be Supplied by Control Area Operators.

The ISO and each adjacent Control Area Operator shall keep each other informed of any change or potential change in the status of the Interconnection and any changes in the Interconnection's TTC. The ISO and each adjacent Control Area Operator shall keep each other informed of situations such as adverse weather conditions, fires, etc., that could affect the reliability of any Interconnection. Each Control Area Operator of the Control Areas in the California area, as defined by the WECC Regional Security Plan, shall keep the ISO informed of all information required by WECC for use by the Reliability

Coordinator.

The ISO and each adjacent Control Area Operator shall follow all applicable NERC and WECC scheduling procedures. This will include checking the Interconnection schedules for the next Settlement Period prior to the start of the Energy ramp going into that hour. The ISO and each adjacent Control Area Operator shall check and agree on actual MWh net interchange after the hour for the previous Settlement Period. One Control Area shall change its actual number to reflect that of the other Control Area in accordance with WECC standard procedures.

The ISO and each adjacent Control Area Operator shall exchange MW, MVar, terminal and bus voltage data with each other on a four second update basis. MWh data for the previous hour shall be exchanged once per hour. All MW and MWh data for both the ISO Control Area and the adjacent Control Areas must originate from the same metering equipment. All provisions in Sections 4.6.1.1(i) and 4.6.1.1(ii) refer to information and data obtained from metering used for Control Area operations and not metering used for billing and settlement.

34.3.7 All Dispatch Instructions except those for the Dispatch of Regulation (which will be communicated by direct digital control signals to Generating Units and, for System Resources, through dedicated communication links which satisfy the ISO's standards for external imports of Regulation) will be communicated electronically, except that, at the ISO's discretion, Dispatch Instructions may be communicated by telephone, or fax. Except in the case of deteriorating system conditions or emergency, and except for instructions for the Dispatch of Regulation, the ISO will send all Dispatch Instructions to the Scheduling Coordinator for the Generating Unit, System Unit, Load or System Resource, which it wishes to Dispatch. The recipient Scheduling Coordinator shall ensure that the Dispatch Instruction is communicated immediately to the operator of the Generating Unit, System Unit, external import of System Resources or Load concerned. If the ISO considers that there has been a failure at a particular point in time or inadequate response over a particular period of time by the Generating Units to the Dispatch Instruction, the ISO will notify the relevant Scheduling Coordinator. The ISO may, with the prior permission of the Scheduling Coordinator concerned, communicate with and give Dispatch Instructions to the operators of Generating Units, System Units, external imports of System Resources and Loads

directly without having to communicate through their appointed Scheduling Coordinator. The ISO shall record the communications between the ISO and Scheduling Coordinators relating to Dispatch Instructions in a manner that permits auditing of the Dispatch Instructions, and of the response of Generating Units, System Units, external imports of System Resources and Loads to Dispatch Instructions. In situations of deteriorating system conditions or emergency, the ISO reserves the right to communicate directly with the Generator(s) as required to ensure System Reliability. The recipient of a Dispatch Instruction shall confirm the Dispatch Instruction. Dispatch Instructions communicated by the ISO either electronically or by fax shall be confirmed electronically in accordance with ISO procedures. Dispatch instructions communicated verbally shall be confirmed by repeating the Dispatch instructions to the ISO.

The ISO Tariff and Protocols govern the content, issue, receipt, confirmation and recording of Dispatch Instructions.

34.4 Notification of Non-Compliance With A Dispatch Instruction.

In the event that, in carrying out the Dispatch Instruction, an unforeseen problem arises (relating to plant operations or equipment, personnel or the public safety), the recipient of the Dispatch Instruction must notify the ISO or, in the case of a Generator, the relevant Scheduling Coordinator immediately. The relevant Scheduling Coordinator shall notify the ISO of the problem immediately.

34.5 Dispatch Instructions for Generating Units and Curtailable Demand.

The ISO may issue Dispatch Instructions covering:

- (a) Ancillary Services;
- (b) Supplemental Energy, which may be used for:
 - (i) Congestion Management;
 - (ii) provision of Imbalance Energy; or
 - (iii) replacement of an Ancillary Service;
- (c) agency operation of Generating Units, Curtailable Demands or Interconnection

schedules, for example:

- (i) output or Demand that can be Dispatched to meet Applicable Reliability Criteria;
- (ii) Generating Units that can be Dispatched for Black Start;
- (iii) Generating Units that can be Dispatched to maintain governor control regardless of their Energy schedules; or
- (d) the operation of voltage control equipment applied on Generating Units as described in this ISO Tariff.

34.6 Response Required by Generators to ISO Dispatch Instructions.

Generators must:

- (a) comply with Dispatch Instructions immediately upon receipt and shall respond in accordance with Good Utility Practice;
- (b) meet voltage criteria in accordance with the provisions specified in the ISO Tariff;
- (c) meet the applicable operational ramp rates as provided for in Section 30.4.6 ;
- (d) respond to Dispatch Instructions for Ancillary Services within the time periods required by this ISO Tariff except in a System Emergency, when Section 7.4 will apply; and (in the case of Generating Units providing Regulation) respond to electronic signals from the EMS; and
- (e) respond to a Dispatch Instruction issued for the start-up or shut down of a Generating Unit, within the time frame stated in the Instruction.

34.7 Qualifying Facilities.

Where a Qualifying Facility ("QF") has entered into an agreement with a PTO before March 31, 1997 for the supply of Energy to the PTO (an "Existing Agreement"), the ISO will follow the instructions provided by the parties to the Existing Agreement regarding the provisions of the Existing Agreement in the performance of its functions relating to Outage Coordination, and not require a QF to take any action that

would interfere with the QF's obligations under the Existing Agreement. Each QF will make reasonable efforts to comply with the ISO's instructions during a System Emergency without penalty for failure to do so.

34.8 Failure to Conform to Dispatch Instructions.

All Scheduling Coordinators, Participating Generators, owners or operators of Curtailable Demands and operators of System Resources providing Ancillary Services (whether self-provided or procured by the ISO) or whose Supplemental Energy bids have been accepted by the ISO shall be obligated to respond or to secure response to the ISO's Dispatch Instructions in accordance with their terms, and to be available and capable of doing so, for the full duration of the Settlement Period. Dispatch Instructions will be deemed delivered and associated Energy will be settled as Instructed Imbalance Energy in accordance with Section 11.2.4.1.1. If a Generating Unit, Curtailable Demand or System Resource is unavailable or incapable of responding to a Dispatch Instruction, or fails to respond to a Dispatch Instruction in accordance with its terms, the Generating Unit, Curtailable Demand or System Resource:

- (a) shall be declared and labeled as non-conforming to the ISO's instructions unless it has notified the ISO of an event that prevents it from performing its obligations within 30 minutes of the onset of such event through a SLIC log entry. Notification of non-compliance via the Automated Dispatch System (ADS) will not supplant nor serve as the official notification mechanism to the ISO;
- (b) cannot set the Dispatch Interval Ex Post Price pursuant to Section 34.9.2.3; and
- (c) the Scheduling Coordinator for the Participating Generator, owner or operator of the Curtailable Demand or System Resource concerned shall have Uninstructed Imbalance Energy due to the difference between the Generating Unit's, Curtailable Demand's or System Resource's instructed and actual output (or Demand). The Uninstructed Imbalance Energy shall be subject to the settlement for Uninstructed Imbalance Energy in accordance with Section 11.2.4.1 and the Uninstructed Deviation Penalty in accordance with Section 11.2.4.1.2. This applies whether the Ancillary Services concerned are contracted or self-provided.

The ISO will develop additional mechanisms to deter Generating Units, Loads, Curtailable Demand and System Resources in the ISO or other Control Areas from failing: (i) to respond at a particular time (or failing to adequately respond over a particular period of time) to a Dispatch Instruction, or (ii) to perform according to Dispatch instructions. The additional mechanisms, for example, can include reduction in payments to Scheduling Coordinators, or suspension of the Scheduling Coordinator's Ancillary Services certificate for the Generating Unit, Curtailable Demand or System Resource concerned. The ISO may apply penalties, fines, economic consequences or the sanctions referred to in the preceding two sentences for any failure or inadequate response under Section 34.3.7 to the Scheduling Coordinator representing the Generator responsible for such failure or inadequate response (which may be appropriately weighted to reflect its seriousness) subject to any necessary FERC approval.

34.9 Pricing Imbalance Energy.

34.9.1 General Principles.

Instructed and Uninstructed Imbalance Energy shall be paid or charged the applicable Resource-Specific Settlement Interval Ex Post Price or the Zonal Settlement Interval Ex Post Price except for hourly pre-dispatched Instructed Imbalance Energy, which shall be settled as set forth in Appendix N, Part D, Section 2.1.2. These prices are determined using the Dispatch Interval Ex Post Prices. The Dispatch Interval Ex Post Prices shall be based on the bid of the marginal Generating Units, System Units, and Curtailable Demand dispatched by the ISO to increase or reduce Demand or Energy output in each Dispatch Interval as provided in Section 34.9.2.1.

The marginal bid is the highest bid that is accepted by the ISO's RTD Software for increased energy Supply or the lowest bid that is accepted by the ISO's RTD Software for reduced energy Supply. In the event the lowest price decremental bid accepted by the ISO is greater and not equal to the highest priced incremental bid accepted, then the Dispatch Interval Ex-Post Price shall be equal to the highest incremental bid accepted when there is a non-negative Imbalance Energy system requirement and equal to the lowest accepted decremental bid when there is a negative Imbalance Energy requirement.

When an Inter-Zonal Interface is operated at the capacity of the interface (whether due to scheduled uses of the interface, or decreases in the capacity of the interface), the marginal incremental or decremental

bid prices in some Zones may differ from one another. In such cases, the ISO will determine separate Ex Post Prices for the Zones.

The ISO will respond to the Dispatch instructions issued by the RTD Software to the extent practical in the time available and acting in accordance with Good Utility Practice. The ISO will record the reasons for any variation from the Dispatch instructions issued by the RTD Software.

34.9.2 Determining Ex Post Prices.

34.9.2.1 Dispatch Interval Ex Post Prices.

34.9.2.2 Computation.

For each Dispatch Interval, the ISO will compute updated supply and demand curves, using the Generating Units, System Units, and Curtailable Demand Dispatched according to the ISO's RTD Software during that time period to meet Imbalance Energy requirements and to eliminate any Price Overlap. The Dispatch Interval Ex Post Price is equal to the bid price of the marginal resource accepted by the ISO for Dispatch, subject to any limitation applicable under Section 34.9.2.1. In the event of Inter-Zonal Congestion, the ISO will determine separate Dispatch Interval Ex Post Prices for each Zone or groups of Zones on either side of the Congested interface.

34.9.2.3 Eligibility.

A resource constrained at an upper or lower operating limit, a boundary of a Forbidden Operating Region or dispatched for the maximum Energy deliverable based on its maximum applicable ramp rate cannot be marginal (i.e., it cannot move in a particular direction) and thus is not eligible to set the Dispatch Interval Ex Post Price. System Resources are not eligible to set the Dispatch Interval Ex Post Price. **Constrained Output Generation that has the ability to be committed or shut off within the two-hour time horizon of the Real Time Market** will be eligible to set the Dispatch Interval Ex Post Price if any portion of its Energy is necessary to serve Demand.

34.9.2.4 Hourly Ex Post Price.

The Hourly Ex Post Price in a Settlement Period in each Zone will equal the absolute-value Energy-

weighted average of the Dispatch Interval Ex Post Prices in each Zone, where the weights are the system total Instructed Imbalance Energy, except Regulation Energy, for the Dispatch Interval. If the ISO declares a System Emergency, e.g. during times of supply scarcity, and involuntary Load Shedding occurs during the real-time Dispatch, the ISO shall set the Hourly Ex Post Price at the Administrative Price.

34.9.2.5 Price for Uninstructed Deviations for Participating Intermittent Resources.

Deviations associated with each Participating Intermittent Resource in a Scheduling Coordinator's Zonal portfolio shall be settled as provided in Section 11.2.4.5.1 at the monthly weighted average Dispatch Interval Ex Post Price, where the weights are the quantities of Instructed Imbalance Energy associated with each Dispatch Interval Ex Post Price.

35 [Not Used]

36 FIRM TRANSMISSION RIGHTS.

36.1 General.

36.1.1 Commencing in 2000, on the effective date established by the ISO Governing Board, the ISO shall make FTRs available in the amounts determined in accordance with Section 36.3, with the rights and other characteristics described in Sections 36.2, 36.6, 36.7 and 36.8, and through the processes described in Section 36.4. Proceeds of the ISO's auction of FTRs shall be distributed as described in Section 36.5. The owners of FTRs shall be entitled to share in Usage Charge revenues associated with Inter-Zonal Congestion in accordance with Section 36.6, and to scheduling priority in the event of Congestion in the Day-Ahead Market, as described in Section 36.7. For the purpose of Section 36, the term "Zone" shall be construed to mean both "Zone" and "Scheduling Point."

36.2 Characteristics of Firm Transmission Rights.

36.2.1 Each FTR shall be defined by a transmission path from an originating Zone to a contiguous receiving Zone. Each FTR shall entitle the FTR Holder to a share of Usage Charges attributable to Inter-Zonal Congestion for transfers on that path from the designated originating Zone to the designated receiving Zone in accordance with Section 36.6. An FTR is a right in one direction only. An FTR Holder shall not be entitled to share in (i) Usage Charges attributable to Inter-Zonal Congestion

from the designated receiving Zone to the designated originating Zone; or (ii) Usage Charges payable in accordance with Section 27.1.2.1.5.1 to a Scheduling Coordinator that counter-schedules from the designated originating Zone to the designated receiving Zone.

36.2.2 The ISO Governing Board shall, from time to time, approve the amount of FTRs to be auctioned for each FTR Market and the ISO shall publish this information on the ISO Home Page at least thirty (30) days prior to the auction. The ISO may issue FTRs in one or more auctions in any year so long as the total FTRs for any interface do not exceed the maximum amount permitted in Section 36.3.

36.2.2.1 Should the ISO create additional Zones or otherwise change the ISO's defined Inter-Zonal Interface, and if such changes would affect outstanding FTRs, such changes will not take effect prior to the expiration date of any such outstanding FTRs. The ISO shall also publish an announcement of any such pending changes on the ISO Home Page and WEnet at least thirty (30) days prior to the applicable FTR auction.

36.2.2.2 Any additional FTRs auctioned as a result of changes in the ISO's defined Inter-Zonal Interfaces shall not affect the rights associated with existing FTRs.

36.2.3 Each FTR shall be issued in the denomination of 1 MW. The annual release of FTRs shall start with the hour beginning at 12:00 a.m., on April 1 and end with the hour beginning at 11:00 p.m., on March 31 of the following year. An FTR shall not afford the FTR Holder any right to share in Usage Charges attributable to Inter-Zonal Congestion occurring in any hour before or after the term of the FTR.

36.2.4 The portion of the Usage Charges to which the FTR Holder is entitled shall be determined in accordance with Section 36.6.

36.2.5 FTR Holders shall be entitled to priority in the scheduling of Energy in the Day-Ahead Market as specified in Section 36.7.

36.2.6 Any entity, with the exception of the ISO, shall be eligible to acquire FTRs by participating in the ISO's auction of FTRs, as described in Section 36.4, or by purchasing FTRs in secondary markets. To participate in the ISO's auction of FTRs, an entity must either be a certified Scheduling Coordinator or have met financial requirements equivalent to the financial certification criteria required of all Scheduling

Coordinators. An entity may not acquire FTRs with a total value that exceeds the financial security proved by that entity to the ISO. In addition, an FTR Bidder must have, or have access to, the necessary technical equipment to participate in the electronic auction.

36.2.7 All entities which acquire FTRs by participating in the ISO's auction of FTRs, as described in Section 36.4, directly from the ISO pursuant to Section 36.4.3, or by purchasing FTRs in secondary markets, must register as an FTR Holder with the ISO. To complete this registration, the FTR Holder must notify the ISO, through the form specified for that purpose by the ISO, of all Affiliates of the FTR Holder that are themselves FTR Holders or Market Participants. The requirement that an FTR Holder notify the ISO of all Affiliates that are FTR Holders or Market Participants is continuing for as long as the FTR Holder owns FTRs, and FTR Holders must provide the ISO with supplemental notification concerning FTR Holders and/or Market Participants that become affiliated with the FTR Holder or Affiliates that subsequently become FTR Holders or Market Participants in order to satisfy this requirement.

36.3 Maximum Number of Firm Transmission Rights.

36.3.1 On each Inter-Zonal Interface and direction combination for which FTRs are issued, the ISO shall issue a number of FTRs that is less than or equal to the difference between:

- (i) The WECC approved path rating of the interface in the direction from the originating Zone to the receiving Zone or, if the interface has not received a WECC approved rating, a rating determined by a methodology that is consistent with the WECC's rating methodology; and
- (ii) The portion of the transfer capability of the interface available for transmission scheduling under Existing Contracts as Existing Rights.

and ensures the ISO's ability to honor all of its FTRs simultaneously under normal operating conditions.

36.4 Issuance of Firm Transmission Rights by the ISO.

36.4.1 The ISO shall make FTRs available by conducting an annual primary auction of FTRs, commencing approximately two months before the beginning of the term of the FTRs; provided; however

that for the initial FTR release, the primary auction shall be as determined by the ISO Governing Board. The auction of FTRs shall be a simultaneous multi-round, clearing price auction conducted separately and independently, as set forth in Section 36.4.2, for each FTR Market. In addition, if the ISO Governing Board decides to make available, between annual auctions, FTRs in addition to those that were purchased in the last annual auction, the ISO may conduct additional auctions of such FTRs in accordance with Section 36.4.2. The term of such FTRs shall only be for the remaining duration of the FTR term defined for the primary auction applicable to the year during which they were issued.

36.4.2 The ISO shall conduct the auction of FTRs through the following procedures:

36.4.2.1 At least thirty (30) days prior to the scheduled start of the auction, the ISO shall post on the ISO Home Page the following information:

- (i) the number of FTRs to be issued for each FTR Market;
- (ii) the starting bid price at which FTRs will be made available in each FTR Market in the first round of the auction, which price will be set in each FTR Market at a level equal to the greater of (a) \$100 per MW-year; (b) twenty (20) percent of the ratio of the net Usage Charges collected by the ISO with respect to that FTR Market in the most recent twelve-month period for which data are available to the total MW-years of Energy scheduled over the Inter-Zonal Interface in the relevant direction during that period; or (c) twenty (20) percent of the ratio of the net Grid Operation Charges (for new Inter-Zonal Interfaces that previously were transmission paths within a Zone) collected by the ISO in the most recent twelve-month period for which data are available to the total MW-years of Energy scheduled over the transmission paths in the relevant direction during that period, provided that, if data are available for only a portion of the twelve-month period, such data shall be used on annualized basis;
- (iii) the formula through which the ISO will determine how much to adjust the price of FTRs in each FTR Market for subsequent rounds of the auction, including the initial coefficients to be used in the formula and the range over which the

coefficients may be adjusted in accordance with Section 36.4.2.3;

- (iv) the date and time prior to the commencement of the auction by which each entity desiring to bid on FTRs must have satisfied the necessary financial requirements as outlined in Section 36.2.6;
- (v) the specifications for the technical equipment necessary to participate in the auction, which will be conducted electronically, the date and time by which bids must be submitted in the first round of the auction, which shall be the same for all FTR Markets, and the form and format in which bids must be submitted; and
- (vi) a schedule for the conduct of subsequent rounds of the auction, including the interval between rounds of the auction and the anticipated duration of the auction.

36.4.2.2 On or before the date specified in Section 36.4.2.1(v), any entity desiring to obtain FTRs in the ISO's auction must submit, via equipment satisfying the technical requirements specified in accordance with Section 36.4.2.1(v), a bid for each FTR Market in which the entity desires to participate, specifying the number of FTRs the entity is willing to purchase at the price specified in Section 36.4.2.1(ii). All individual bids will remain confidential throughout all rounds of the auction in each FTR Market. Once submitted to the ISO, a bid for FTRs in any round of an auction may not be cancelled or rescinded by the FTR Bidder. The ISO shall announce simultaneously to all FTR Bidders the total quantity of FTRs for which valid bids are submitted for each FTR Market.

36.4.2.3 In each round of the auction following the first round, the ISO will increase the price at which FTRs are made available in each FTR Market in accordance with the formula posted in accordance with Section 36.4.2.1(iii), or in accordance with any adjustment to the coefficients in that formula that is announced by the ISO to the FTR Bidders at least one round in advance of the round for which the adjustment is made. Price increases need not be uniform for all FTR Markets. In the case of an FTR Market in which the demand for FTRs in the preceding round is less than or equal to the quantity of FTRs being made available, the price shall not increase and the auction for that FTR Market shall close. After each round of the auction, the ISO shall announce simultaneously to all FTR Bidders the total quantity of

FTRs for which valid bids were submitted in each FTR Market, whether the auction for each FTR Market is closed, and, the revised prices for the following round of the auctions that remain open. Within the timeframe set by the ISO in accordance with Section 36.4.2.1(vi), each FTR Bidder may submit bids for the quantity of FTRs it desires to purchase in each FTR Market at the revised price, provided that an FTR Bidder may not bid for a number of FTRs in an FTR Market that exceeds the total number of FTRs in that FTR Market for which that entity submitted bids in the preceding round of the auction. The ISO shall conduct subsequent rounds of the auction in each FTR Market until the demand for FTRs in the FTR Market is less than or equal to the quantity of FTRs being made available, at which point the auction shall be closed in that FTR Market.

36.4.2.4 Subject to Section 36.4.2.5, each successful FTR Bidder shall receive a number of FTRs in each FTR Market equal to the number of FTRs for which it bid in the last round of the auction for that FTR Market.

36.4.2.5 For any FTR Market in which, when the auction has closed, the number of FTRs being made available exceeds the demand for FTRs in that FTR Market in the last round of the auction, each FTR Bidder shall be awarded a number of FTRs determined in accordance with the following formula, provided that, if the number of FTRs that would be awarded under the formula to an FTR Bidder that did not submit a bid in the last round of the auction is less than five percent (5%) of the initial bid submitted by that FTR Bidder for the FTR Market, that FTR Bidder shall have the option of declining the award of FTRs resulting from the formula:

$$N = B + [(R / TR) * D]$$

where

N = The total number of FTRs awarded to an FTR Bidder for an FTR Market, which shall be in whole MWs and shall not exceed the number of FTRs for which that FTR Bidder bid in the round preceding the final round of the auction;

B = The number of FTRs for which an FTR Bidder bid in the final round of the auction for the FTR Market in accordance with Section 36.4.2.4 (or zero, if the FTR Bidder did not bid in

that round);

R = The difference between the number of FTRs for which the FTR Bidder bid in the round preceding the final round of the auction and B, but not less than zero;

TR = The total of the demand reductions (R) for all FTR Bidders that submitted bids in the last round of the auction (treating the failure by an FTR Bidder to submit a bid as a bid of zero); and

D = The difference between the total demand for FTRs in the final round of the auction and the quantity of FTRs being made available for the FTR Market.

36.4.2.6 The price of FTRs in an FTR Market shall be the last price at which the demand for FTRs in the FTR Market exceeded or equaled the quantity of FTRs being made available pursuant to Section 36.4.2.1(i), except that, if the demand for FTRs in an FTR Market in the first round of the auction was less than the quantity of FTRs being made available for that FTR Market, the price of FTRs in that FTR Market shall be the first round price and each FTR Bidder in that FTR Market will receive a number of FTRs equal to the quantity of bids they submitted in the first round. Any remaining FTRs in that FTR Market will not be awarded in that auction.

36.4.2.7 Each FTR Bidder shall pay the ISO an amount equal to the sum, for all FTR Markets, of the products of the FTR price in each FTR Market (determined in accordance with Section 36.4.2.6) and the total quantity of FTRs awarded to that FTR Bidder in that FTR Market (determined in accordance with Section 36.4.2.4 or Section 36.4.2.5, as applicable). FTR Bidders shall pay the amount determined in accordance with the foregoing sentence within ten (10) Business Days of receiving an invoice from the ISO by making payment to the ISO Clearing Account in accordance with Section 11.10. If the FTR Bidder fails to make timely payment of the full amount due, the ISO may enforce any guarantee, letter of credit or other credit support provided by the defaulting FTR Bidder in accordance with Section 36.2.6 and, if the ISO is required to institute proceedings to collect any unpaid amount, the defaulting FTR Bidder shall pay Interest on the unpaid amount for the period from the Payment Date until the date on which payment is remitted to the ISO Clearing Account.

36.4.2.8 The ISO shall post on the ISO Home Page the prices at which FTRs are sold in each FTR Market through the primary auction.

36.4.3 For the ten-year transition period described in Section 4 of Schedule 3 to Appendix F, a New Participating TO that has an obligation to serve Load shall receive FTRs for Inter-Zonal Interfaces to which the transmission facilities and Converted Rights for Inter-Zonal Interfaces that the New Participating TO turns over to the ISO's Operational Control give it transmission rights, provided such transmission facilities are Existing High Voltage Facilities. The amount of FTRs will be determined when the Transmission Control Agreement is executed and shall be commensurate with the transmission capacity the New Participating TO is turning over to ISO Operational Control. The ISO will submit to FERC in the transmittal letter for the amendment to the Transmission Control Agreement regarding each New Participating TO the amount of FTRs allocated to such New Participating TO. The amount of FTRs that has been determined will not be effective until after FERC issues an order concerning the amendment required by this section. No additional FTRs will be issued to New Participating TOs for building High Voltage Transmission Facilities after they become Participating TOs. FTRs issued in accordance with this section shall entitle the FTR Holder to receive Usage Charge revenues and to priority in the scheduling of Energy in the Day-Ahead Market in accordance with the provisions of the ISO Tariff. FTRs associated with Converted Rights shall terminate on the earlier of termination of the Existing Contract or the end of the ten-year transition period.

36.5 Distribution of Auction Revenues Received by the ISO for Firm Transmission ` Rights.

36.5.1 For each Inter-Zonal Interface and direction for which an FTR is defined, the total proceeds received by the ISO through the auction described in Section 36.4 shall be allocated and paid by the ISO to the Participating TO that is entitled in accordance with Section 27.1.2.1.6 to receive Usage Charge revenues with respect to the corresponding Inter-Zonal Interface. Each Participating TO shall credit its FTR auction proceeds against its high voltage TRBA if the FTR is for a High Voltage Transmission Facility or against its low voltage TRBA if the FTR is a for a Low Voltage Transmission Facility.

36.5.2 In the event the transmission facilities or rights making up an Inter-Zonal Interface with respect to which FTRs are defined are owned by more than one Participating TO, the proceeds of the auction of such FTRs shall be allocated to those Participating TOs who auction FTRs in proportion to the FTRs associated with their Inter-Zonal Interface as of the date of the FTR auction compared to all FTRs auctioned for such Inter-Zonal Interface.

36.5.3 In the event the transmission facilities or rights making up an Inter-Zonal Interface with respect to which FTRs are defined have been upgraded resulting in increased transmission capacity on the Inter-Zonal Interface, and the costs of construction and operation were paid for by a Project Sponsor pursuant to Section 24.7.1 and were not included in the ISO's transmission Access Charge or a reimbursement or direct payment from a Participating TO, the proceeds of the auction of such FTRs shall be allocated to the Project Sponsors according to the allocated shares determined as set forth in Section 24.7.3(d).

36.6 Distribution of Usage Charges to FTR Holders.

36.6.1 The FTR Holder shall be entitled to receive from the ISO a portion of the total Congestion revenues related to Inter-Zonal Congestion calculated by the ISO in the Day-Ahead Market and collected by the ISO with respect to the Inter-Zonal Interface and direction combination for which the FTR was defined. This portion equals the Usage Charge calculated by the ISO in the Day-Ahead Market for the transfer of 1 MW from the originating Zone to the receiving Zone during each hour in which Usage Charges apply, multiplied by the number of FTRs owned by that FTR Holder, subject to adjustment in accordance with Section 36.6.3.

36.6.2 In addition, an FTR Holder shall be entitled to receive a portion of the additional net Usage Charges related to Inter-Zonal Congestion calculated by the ISO in the Hour-Ahead Market and collected by the ISO with respect to the Inter-Zonal Interface and direction combination for which the FTR was defined. The FTR Holder shall receive a portion of the net Usage Charges in the Hour-Ahead Market proportionate to the share of the Usage Charges it received in the Day-Ahead Market in accordance with Section 36.6.1.

36.6.3 When the Day-Ahead scheduling capability of an Inter-Zonal Interface and direction is less than its scheduling capacity, determined in accordance with Section 36.3, prior to the Day-Ahead Market, the entitlements of FTR Holders associated with that FTR Market to Usage Charge revenues shall not be reduced until and unless the entitlements of Participating TOs associated with that FTR Market to Usage Charge revenues in accordance with Section 27.1.2.1.6 have been reduced to zero. In that event, the financial entitlements associated with the corresponding FTRs shall be multiplied by a factor equal to the amount of scheduling capability available to holders of the remaining FTRs divided by the number of such FTRs. When the Day-Ahead scheduling capability of an Inter-Zonal Interface and direction is greater than its scheduling capacity, determined in accordance with Section 36.3, prior to the Day-Ahead Market, the entitlements of FTR Holders associated with that FTR Market to Usage Charge revenues shall not be increased.

36.6.4 When the Congestion Usage Charges calculated and collected by the ISO from the Hour-Ahead Market with respect to transfers across an Inter-Zonal Interface in a particular direction result in a net obligation to the ISO, in the circumstances described in Section 27.1.2.1.7, the provisions of this Section 9.6 shall continue to apply, and FTR Holders shall be required to pay the ISO these amounts.

36.6.5 The ISO will calculate the Congestion Usage Charge revenues to be credited or debited to the account of each FTR Holder on an hourly basis. Such calculation will identify the Inter-Zonal Interface and direction to which each credit or debit applies.

36.7 Scheduling Priority of FTR Holders.

36.7.1 FTRs will not affect the ISO's dispatch and operation of the ISO Controlled Grid except that each FTR Holder will have a priority, as described in this Section 36.7, for the scheduling of Energy in the Day-Ahead Market when an Inter-Zonal Interface experiences Inter-Zonal Congestion in the direction for which its FTR is defined. Any FTRs not used in Preferred Schedules in the Day-Ahead Market for any hour have no scheduling priority for that hour in the Trading Day. FTR Holders shall have no scheduling priority in the Hour-Ahead Market or in real-time operations.

36.7.2 When Inter-Zonal Congestion is experienced or projected to be experienced in the Day-Ahead Market, the ISO shall first attempt to relieve the Inter-Zonal Congestion using Adjustment Bids

submitted by Scheduling Coordinators in accordance with Section 27.1.1.4.

36.7.2.1 If the ISO is unable to relieve the Day-Ahead Inter-Zonal Congestion using Adjustment Bids, then the ISO will allocate Day-Ahead inter-zonal transmission capacity first to Schedules of Market Participants that are using Existing Contract rights that have higher scheduling priority than Converted Rights capacity and second to Market Participants who hold FTRs and have indicated to the ISO that they wish to exercise their scheduling priority option. The ISO will allocate any remaining transmission capacity to remaining Market Participants' Schedules pro rata.

36.7.3 When the scheduling capability of an Inter-Zonal Interface is less than or greater than its normal scheduling capability prior to the Day-Ahead Market, as described in Section 36.6.3, the priority scheduling rights of FTR Holders, as described in Section 36.7.2, shall remain constant (in MWs) to the extent that the total scheduling rights of FTR Holders do not exceed the total Interface scheduling capability of the associated Inter-Zonal Interface after adjustments have been made for transmission capacity allocated to Existing Contract rights that have higher scheduling priority than Converted Rights. If the total Interface scheduling capability, adjusted for transmission capacity allocated to Existing Contract rights that have higher scheduling priority than Converted Rights, is less than the total of all scheduling capability represented by FTR Holders who have chosen to exercise the FTR scheduling priority option, scheduling capability shall be allocated to FTR Holders pro rata.

36.7.4 The scheduling priority of FTR Holders:

- (i) Shall not apply in the Hour-Ahead Market or in real-time dispatch and operation of the ISO Controlled Grid;
- (ii) Shall not apply to any transfer of Energy other than a transfer across the Inter-Zonal Interface in the direction for which the FTR was defined during the hour or hours during which the circumstances described in Section 36.7.2.1 apply; and
- (iii) Shall not be transferable, except in connection with a transfer of the FTR that is registered with the ISO, as described in Section 36.8.

36.8 Assignment of Firm Transmission Rights.

36.8.1 An FTR may be assigned, sold, or otherwise transferred by the FTR Holder to any entity eligible to be an FTR Holder in full MW increments, either for the entire term of the FTR or for any portion of that term providing, however, that any such transfer shall be in full hour increments that correspond to the FTR issued to the FTR Holder. All FTRs that are so assigned, sold, or otherwise transferred by the FTR Holder are subject to the terms and conditions for FTRs approved by FERC and set forth in the ISO Tariff. Both the FTR Holder of record and the entity to which the FTRs have been transferred shall register the transfer of the FTR with the ISO by notifying the ISO through the form specified for that purpose by the ISO, and within the number of Business Days following the transfer published by the ISO on the ISO Home Page and WEnet but no later than such time as the ISO shall specify before the deadline applicable to scheduling Energy in the Day-Ahead Market, of (i) the identity of the FTR Holder of record; (ii) the identity of the entity to which the FTRs have been transferred; (iii) the quantity and identification numbers of the FTRs being transferred; (iv) the portion of the term of the FTR for which they are transferred; (v) the price at which the FTRs are being transferred; and (vi) whether the transfer of FTRs is subject to any conditions. The entity to which the FTRs have been transferred must also notify the ISO of all entities with which the transferee is affiliated that are FTR Holders or Market Participants as defined in the ISO Tariff, pursuant to Section 36.2.7. After the ISO receives such notices, the transferee shall be considered the FTR Holder of record with respect to the portion of the term of the FTR that is transferred. In order to use the Scheduling Priority of an FTR, pursuant to Section 36.7, an FTR must be registered with the ISO.

36.8.2 The ISO shall publish on the ISO Home Page such information concerning the concentration of ownership of FTRs in each FTR Market as determined by the ISO Governing Board from time to time.

36.8.3 To facilitate the operation of secondary markets in FTRs, the ISO shall post on WEnet and the ISO Home Page: (i) the identity of entities that hold FTRs that have been registered with the ISO, together with the quantity of FTRs held by such entities in each FTR Market and the path rating of the interface; and (ii) the name and a contact telephone number or telecopy number of any entity that

operates a secondary market in FTRs and that requests the ISO to post such information. The ISO shall also post the prices at which FTRs are transferred through secondary market transactions and shall indicate whether such transfers are conditional.

37 ENFORCEMENT PROTOCOL.

37.1 Objectives, Definitions, and Scope.

37.1.1 Purpose.

This Section sets forth the guiding principles for participation in the markets administered by the California Independent System Operator. The specified Rules of Conduct are intended to provide fair notice to Market Participants of the conduct expected of them, to provide an environment in which all parties may participate on a fair and equal basis, to redress instances of gaming and other instances of anticompetitive behavior, and thereby to foster confidence of Market Participants, ratepayers and the general public in the proper functioning of the ISO markets.

37.1.2 Objectives.

The objectives of this ISO Tariff are to:

- (a) Provide clear Rules of Conduct specifying the behavior expected of Market Participants;
and
- (b) Establish in advance the Sanctions and other potential consequences for violation of the specified Rules of Conduct.

37.1.3 Application of Other Remedies.

The activities and remedies authorized under this Section 37 are in addition to any other actions or relief that may be available to the ISO elsewhere in the ISO Tariff or under law, regulation or order. Nothing in this Section 37 limits or should be construed to limit the right of the ISO to take action or seek relief otherwise available to it, and such action or relief may be pursued in lieu of or in addition to the action or relief specified in this Section 37.

37.1.4 FERC Authority.

In addition to any authority afforded Market Monitoring Unit in this Section 37, FERC shall have the authority to assess the sanctions, and otherwise to enforce the rules as set forth and described in this Section 37. FERC shall have authority to remedy a violation under this Section 37 from the date of the violation. Nothing in this Section 37 shall be deemed to be a limitation or condition on the authority of FERC or other entities under current law or regulation.

37.1.5 Administration.

The Marketing Monitor Unit will administer the Rules of Conduct specified herein, except for Section 37.7, which shall be administered by FERC, and except as provided in Section 37.2.5 and Section 37.4.4. Nothing in this ISO Tariff limits or should be construed to limit the ability of components of the ISO organization other than the Market Monitoring Unit to analyse data and refer matters to the Market Monitoring Unit for enforcement.

37.2 Comply with Operating Orders.

37.2.1 Compliance with Orders Generally.

37.2.1.1 Expected Conduct.

Market Participants must comply with operating orders issued by the ISO as authorized under the ISO Tariff. For purposes of enforcement under this Section 37.2, an operating order shall be an order(s) from the ISO directing a Market Participant to undertake, a single, clearly specified action (e.g., the operation of a specific device, or change in status of a particular Generating Unit) that is feasible and intended to resolve a specific operating condition. A Market Participant's failure to obey an operating order containing multiple instructions to address a specific operating condition will result in a single violation of Section 37.2. If some limitation prevents the Market Participant from fulfilling the action requested by the ISO, then the Market Participant must promptly and directly communicate the nature of any such limitation to the ISO. Compliance with ISO operating orders requires a good faith effort to achieve full performance as soon as is reasonably practicable in accordance with Good Utility Practice.

37.2.1.2 Sanctions.

The Sanction for a violation of this Section shall be the greater of the quantity of Energy non-performance multiplied by the applicable Hourly Ex Post Price or the following: for the first violation in a rolling twelve (12) month period, \$5,000; for the second and subsequent violations in a rolling twelve (12) month period, \$ 10,000. Sanctions under Section 37.2.1 will not be greater than \$10,000 per violation and will be subject to the limitation stated in Section 37.2.6. If a quantity of energy cannot be objectively determined, then the financial sanctions specified above will apply. A Market Participant may incur Sanctions for more than one violation per day.

37.2.2 Failure to Curtail Load.

37.2.2.1 Expected Conduct.

A UDC or MSS Operator shall promptly comply with any ISO operating order to curtail interruptible or firm load issued pursuant to the ISO's authority under Section 7.4.11.3 of the ISO Tariff.

37.2.2.2 Sanctions.

The Sanction for non-compliance with an operating order to curtail load will be \$10,000 for each violation.

37.2.3 Operations & Maintenance Practices.

37.2.3.1 Expected Conduct.

Market Participants shall undertake such operating and maintenance practices as necessary to avoid contributing to a major outage or prolonging response time as indicated by Section 7.4.13.3 of the ISO Tariff.

37.2.3.2 Sanctions.

The Sanction for a violation of Section 37.2.3 will be \$10,000.

37.2.4 Must-Offer Denials/Revocations.

37.2.4.1 Expected Conduct.

A Market Participant shall start a Generating Unit and have that Generating Unit operating at minimum

load within 30 minutes of the time at which a must-offer waiver revocation becomes effective, or report the derate, outage or other event outside the control of the Market Participant that prevents the Generating Unit from being started by such time. Notwithstanding the foregoing, no violation shall occur unless the Market Participant has been provided advance notice of the waiver revocation consistent with the relevant start-up time set forth in the ISO Master File. A Market Participant that fails to perform in accordance with the expected conduct described in this Section 37.2.4.1 shall be subject to Sanction.

37.2.4.2 Sanctions.

The Sanctions for a violation of Section 37.2.4 shall be as follows: for the first violation in a rolling twelve (12) month period, \$5,000; for the second and all subsequent violations in a rolling twelve (12) month period, \$10,000. A Market Participant is limited to one Sanction per Generating Unit per calendar day.

37.2.5 Enhancements and Exceptions.

Except as otherwise specifically provided, penalty amounts shall be tripled for any violation of Section 37.2.1 through Section 37.2.4 if an ISO System Emergency exists at the time an operating order becomes effective or at any time during the Market Participant's non-performance. Notwithstanding the foregoing, violations of Section 37.2.1 through Section 37.2.4 are subject to penalty under this rule only to the extent that the ISO has issued a separate and distinct non-automated Dispatch Instruction to the Market Participant. Any penalty amount that is tripled under this provision and that would exceed the \$10,000 per day penalty limit shall not be levied against a Market Participant until the ISO proposes and the Commission approves such an enhancement. A Market Participant that is subject to an enhanced penalty amount under this Section 37.2.5 may appeal that penalty amount to FERC if the Market Participant believes a mitigating circumstance not covered in Section 37.9.2 exists. The duty of the Market Participant to pay the enhanced penalty amount will be tolled until FERC renders its decision on the appeal.

37.2.6 Per-Day Limitation on Amount of Sanctions.

The amount of Sanctions that any Market Participant will incur for committing two or more violations of Section 37.2.1 through Section 37.2.4 on the same day will be no greater than \$10,000 per day.

37.3 Submit Feasible Energy and Ancillary Service Bids and Schedules.

37.3.1 Bidding Generally.

37.3.1.1 Expected Conduct.

Market Participants must bid and schedule Energy and Ancillary Services from resources that are reasonably expected to be available and capable of performing at the levels specified in the bid and/or schedule, and to remain available and capable of so performing based on all information that is known to the Market Participant or should have been known to the Market Participant at the time of bidding or scheduling. Hourly Pre-Dispatched bids for import or export of Supplemental Energy are not subject to the foregoing requirement, but failure to deliver on such pre-dispatched bids can violate the anti-manipulation rule in Section 37.7 and in any regulations issued by FERC.

37.3.1.2 Consequence for Non-Performance.

A Market Participant that fails to perform in accordance with the expected conduct described in Section 37.3.1.1 above shall be subject to having the payment rescinded for any portion of an Ancillary Service that is unavailable. If a Market Participant fails to deliver on an Hourly Pre-Dispatch bid for import or export of Supplemental Energy, it shall be subject to any charge that may apply in Section 11.31 and to any penalty or sanction FERC may impose for violation of Section 37.7, but shall not be subject to Sanctions pursuant to any other provision of Section 37, including this Section 37.3.

37.3.2 Exceptions.

Violations of Section 37.3.1 that result in circumstances in which an Uninstructed Deviation Penalty under Section 11.2.4.1.2 of the ISO Tariff may be assessed or for which payments have been eliminated under Section 8.10.2 of the ISO Tariff are not subject to Sanction under this section. The submission of a Schedule that causes, or that the ISO expects to cause Intra-Zonal Congestion shall not, by itself, constitute a violation of Section 37.3.1 unless the Market Participant fails to comply with an obligation under the ISO Tariff to modify Schedules as determined by the ISO to mitigate such congestion or such Schedules violate another element of this Rule.

37.4 Comply with Availability Reporting Requirements.

37.4.1 Reporting Availability.

37.4.1.1 Expected Conduct.

A Market Participant shall notify the ISO Control Center of any Outage reportable pursuant to Section 9.3.10.2.1 of the ISO Tariff of a Generating Unit subject to Section 4.6 of the ISO Tariff within **sixty (60)** minutes after the Outage is discovered.

37.4.1.2 Sanctions.

A "violation" for purposes of this Section shall mean each failure to notify the ISO Control Center about an Outage of a Generating Unit within sixty (60) minutes after the Outage is discovered, as required by Section 37.4.1, except that (a) for each Generating Unit, the first such failure in a calendar month shall not constitute a violation, and (b) for each Generating Unit, multiple failures in the same calendar day shall constitute a single violation. The Sanctions for a violation of Section 37.4.1 shall be as follows:

- (a) for each Generating Unit that is the subject of a violation, the Sanction for the first violation in a calendar month shall be a warning letter;
- (b) for each Generating Unit that is the subject of a violation, the Sanction for the second and subsequent violations in a calendar month will be a financial penalty, as follows:
 - (i) if the Generating Unit has not been the subject of a financial penalty for a previous violation within twelve (12) months of the instant violation, the Sanction will be \$1,000;
 - (ii) if the Generating Unit has been the subject of one financial penalty for a previous violation within twelve (12) months of the instant violation, the Sanction will be \$2,000;
 - (iii) if the Generating Unit has been the subject of two or more financial penalties for previous violations within twelve (12) months of the instant violation, the Sanction will be \$5,000.

37.4.2 Scheduling and Final Approval of Outages.

37.4.2.1 Expected Conduct.

A Market Participant shall not undertake an Outage except as approved by the ISO Outage Coordination Office in accordance with Section 9.3.2, Section 9.3.9, and Section 9.3.6.6 of the ISO Tariff. A Market Participant shall not commence any Outage without obtaining final approval from the ISO Control Center in accordance with Sections 9.3.9 and 9.3.10 of the ISO Tariff.

37.4.2.2 Sanctions.

The Sanctions for a violation of Section 37.4.2 shall be as follows: for the first violation within a rolling twelve (12) month period, \$5,000; for subsequent violations within a rolling twelve (12) month period, \$10,000. A "violation" shall mean each Outage undertaken for which all required approvals were not obtained.

37.4.3 Explanation of Forced Outages.

37.4.3.1 Expected Conduct.

As required by Section 9.3.10.5, a Market Participant must provide a detailed explanation of a Forced Outage within two (2) Business Days after the Operator initially notifies the ISO pursuant to Section 9.3.10.2.1 of the change in maximum output capability. An Operator must promptly provide information requested by the ISO to enable

the ISO to review the explanation submitted by the Operator and to prepare a report on the Forced Outage.

37.4.3.2 Sanctions.

The Sanction for failing to provide a timely explanation of Forced Outage shall be \$500 per day for each day the explanation is late. The Sanction for failing to provide a timely response to information requested shall be as specified in Section 37.6.1.

37.4.4 Enhancements and Exceptions.

Except as otherwise specifically provided, penalty amounts shall be tripled for any violation of Section 37.4.1 through Section 37.4.3 that occurs during an ISO System Emergency. Violations of the above rules that result in circumstances in which an Uninstructed Deviation Penalty under Section 11.2.4.1.2 of the ISO Tariff may be assessed shall not be subject to Sanction under this Section 37.4. A Market Participant that is subject to an enhanced penalty amount under this Section 37.4.4 may appeal that penalty amount to FERC if the Market Participant believes a mitigating circumstance not covered in Section 37.9.2 exists. The duty of the Market Participant to pay the enhanced penalty amount will be tolled until FERC renders its decision on the appeal.

37.5 Provide Factually Accurate Information.

37.5.1 Accurate Information Generally.

37.5.1.1 Expected Conduct.

All applications, Schedules, reports, and other communications by a Market Participant or agent of a Market Participant to the ISO, including maintenance and outage data, bid data, transaction information, and load and resource information, must be submitted by a responsible company official who is knowledgeable of the facts submitted. The Market Participant shall provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with FERC, FERC-approved market monitors, FERC-approved regional transmission organizations, or FERC-approved independent system operators, or jurisdictional transmission providers, unless the Market Participant exercised due diligence to prevent such occurrences.

37.5.1.2 Sanctions.

The Sanctions for a violation of Section 37.5.1 shall be as follows: for the first violation within a rolling twelve (12) month period, \$2,500; for the second violation within a rolling twelve (12) month period, \$5,000; subsequent violations within a rolling twelve (12) month period, \$10,000.

37.5.2 Inaccurate Meter Data.

37.5.2.1 Expected Conduct.

Market Participants shall provide complete and accurate Settlement Quality Meter Data for each Trade hour and shall correct any errors in such data prior to the issuance of Final Settlement Statements. Failure to provide complete and accurate Settlement Quality Meter Data, as required by Section 10 of the ISO Tariff and that results in an error that is discovered after issuance of Final Settlement Statements, shall be a violation of this rule.

37.5.2.2 Sanctions.

Violations under this Section 37.5.2 shall be subject to Sanction described in Section 37.11.

37.5.2.3 Disposition of Sanction Proceeds.

For purposes of redistributing collected penalties, any amounts collected under this provision shall be applied first to those parties affected by the conduct. Any excess amounts shall be disposed of as set forth in Section 37.9.4.

37.6 Provide Information Required by ISO Tariff.

37.6.1 Required Information Generally.

37.6.1.1 Expected Conduct.

Except as provided below in Section 37.6.4 (Review by FERC), all information that is required to be submitted to the ISO under the ISO Tariff, ISO protocols, or jurisdictional contracts must be submitted in a complete, accurate, and timely manner. Market Participants must comply with requests for information or data by the ISO authorized under the ISO Tariff, including timelines specified in the ISO Tariff for

submitting Schedules and other information.

37.6.1.2 Sanctions.

Except as otherwise provided below, in Section 37.6.2 and Section 37.6.3, a violation of this rule is subject to a penalty of \$500 for each day that the required information is late.

37.6.2 Investigation Information.

37.6.2.1 Expected Conduct.

Except as provided below in Section 37.6.4 (Review by FERC), Market Participants must submit timely information in response to a written request by the ISO for information reasonably necessary to conduct an investigation authorized by the ISO Tariff.

37.6.2.2 Sanctions.

The Sanction for a violation of Section 37.6.2 shall be as follows: for the first violation in a rolling 12-month period, \$1000/day; for the second violation in a rolling 12-month period, \$2000/day; for the third and subsequent violations in a rolling 12-month period, \$5000/day. For purposes of this subsection, a violation shall be each failure to provide a full response to a written request and the Sanction shall be determined from the date that the response was due until a full response to the request is received.

37.6.3 Audit Materials.

37.6.3.1 Expected Conduct.

Except as provided below in Section 37.6.4 (Review by FERC), Market Participants shall comply with the ISO's audit and/or test procedures, and further shall perform and timely submit an annual self-audit as required under the ISO Tariff.

37.6.3.2 Sanctions.

For failure to submit an annual Scheduling Coordinator Self Audit report, the Sanction shall be \$1000/day until such report is received by the ISO. For all other violations of this rule the Sanctions shall be as follows: for the first violation in a rolling 12-month period, \$1000/day; for the second violation in a rolling

12-month period, \$2000/day; for the third and subsequent violations in a rolling 12-month period, \$5000/day. For purposes of this subsection, a "violation" shall be each failure to provide all information required under the audit or test, from the date that the information was due until all required information is received by the ISO.

37.6.4 Review by FERC.

A Market Participant who objects to an information, audit or test obligation that is enforceable under Section 37.6.1, Section 37.6.2 or Section 37.6.3 above shall have the right immediately (and in all events, no later than the due date for the information) to seek review of the obligation with FERC. In the event that such review is sought, the time for submitting the response or other information to the ISO shall be tolled until FERC resolves the issue.

37.7 No Market Manipulation.

37.7.1 Market Manipulation Generally.

37.7.1.1 Expected Conduct.

Actions or transactions that are without a legitimate business purpose and that are intended to or foreseeably could manipulate market prices, market conditions, or market rules for electric energy or electricity products are prohibited. Actions or transactions by a Market Participant that are explicitly contemplated in the ISO Tariff or are undertaken at the direction of the ISO are not in violation of this Rule of Conduct.

37.7.1.2 Sanctions.

Violations or potential violations of this rule shall be referred to FERC for appropriate sanction.

37.7.2 Wash Trades.

37.7.2.1 Expected Conduct.

Market Participants shall not engage in pre-arranged offsetting trades of the same product among the same parties, which involve no economic risk and no net change in beneficial ownership (sometimes called "wash trades").

37.7.2.2 Sanctions.

Violations or potential violations of this rule shall be referred to FERC for appropriate sanction.

37.7.3 False Information.

37.7.3.1 Expected Conduct.

A Market Participant shall not engage in transactions predicated on submitting false information to transmission providers or other entities responsible for operation of the transmission grid (such as inaccurate load or generation data; or scheduling non-firm service or products sold as firm), unless the Market Participant exercised due diligence to prevent such occurrences.

37.7.3.2 Sanctions.

Violations or potential violations of this rule shall be referred to FERC for appropriate sanction.

37.7.4 Artificial Congestion.

37.7.4.1 Expected Conduct.

A Market Participant shall not engage in transactions in which it first creates artificial congestion and then purports to relieve such artificial congestion (unless the Market Participant exercised due diligence to prevent such an occurrence).

37.7.4.2 Sanctions.

Violations or potential violations of this rule shall be referred to FERC for appropriate sanction.

37.7.5 Collusion.

37.7.5.1 Expected Conduct.

Market Participants shall not engage in collusion with another party for the purpose of manipulating market prices, market conditions, or market rules for electric energy or electricity products.

37.7.5.2 Sanctions.

Violations or potential violations of this rule shall be referred to FERC for appropriate sanction.

37.8 Process for Investigation and Enforcement.

37.8.1 Purpose; Scope.

The provisions of this Section 37.8 set forth the procedures by which the Market Monitoring Unit will independently investigate potential violations of the Rules of Conduct and administer enforcement activities. Except as hereinafter provided, and except as provided in Section 37.2.5 and Section 37.4.4, the provisions of this section apply to the Rules of Conduct set forth in Sections 37.2 through 37.7.

37.8.2 Referrals to FERC.

Section 37.7 shall be enforced by FERC, in accordance with FERC's rules and procedures. The Market Monitoring Unit shall refer to FERC and its staff all matters in which it has formed a reasonable belief that a violation of Section 37.7 may have occurred. Although Sections 37.2 through 37.6 will generally be enforced by the Market Monitoring Unit, the Market Monitoring Unit shall refer to FERC any matter for which the particular circumstances preclude the objective determination of a Rules of Conduct violation, and shall refer to FERC any Sanction that it believes should be modified in accordance with Sections 37.2.5, 37.4.4, or 37.9.1. The time limitation contained in Section 37.10.1 to assess a Sanction under this Protocol shall be determined as of the date that a Sanction is initially assessed by the ISO, excluding the time required for FERC to investigate a potential Rules of Conduct violation and/or determine a Sanction in accordance with this section, Sections 37.2.5, 37.4.4, or 37.9.1.

37.8.3 Investigation.

The Market Monitoring Unit shall conduct a reasonable investigation seeking available facts, data, and other information relevant to the potential Rules of Conduct violation.

37.8.4 Notice.

The Market Monitoring Unit shall provide notice of the investigation in sufficient detail to allow for a meaningful response to the Scheduling Coordinator and, as limited below, to all Market Participants the Scheduling Coordinator represents that are the subject(s) of the investigation. The Market Monitoring Unit shall contact the Market Participant(s) that may be involved, so long as the ISO has sufficient objective information to identify and verify the role of the Market Participant(s) in the potential Rules of

Conduct violation. Such Market Participant(s) will likely have an existing contractual relationship with the ISO (e.g., UDC, MSS, ISO Metered Entity, Participating Transmission Owner, Participating Generator, or Participating Load).

37.8.5 Opportunity to Present Evidence.

The Market Monitoring Unit shall provide an opportunity to the Market Participant(s) that are the subject(s) of the investigation to present any issues of fact or other information relevant to the potential Rules of Conduct violation being investigated. The Market Monitoring Unit shall consider all such information or data presented.

37.8.6 Results of Investigation.

The Market Monitoring Unit shall notify the Market Participant(s) that are the subject(s) of the investigation of the results of the investigation. The Market Participant(s) shall have 30 days to respond to the findings of the Market Monitoring Unit before the Market Monitoring Unit makes a determination of whether a Sanction is required by this ISO Tariff.

37.8.7 Statement of Findings and Conclusions.

Where the investigation results in a Sanction, the Market Monitoring Unit shall state its findings and conclusions in writing, and will make such writing available to the Scheduling Coordinator and, as provided in Section 37.8.4, to the Market Participant(s) that are the subject(s) of the investigation.

37.8.8 Officer Representative.

Where an investigation results in a Sanction by the Market Monitoring Unit, the Market Monitoring Unit shall direct its notice of such result to a responsible representative of the Scheduling Coordinator and, as provided in Section 37.8.4, to the Market Participant(s) that are the subject(s) of the investigation at the officer level.

37.8.9 Record of Investigation.

Where an investigation results in a Sanction, the Market Monitoring Unit will maintain a record of the investigation until its decision has been finally reviewed, if review is sought, or until the period for seeking

review has expired.

37.8.10 Review of Determination.

A Market Participant that receives a Sanction may obtain immediate review of the Market Monitoring Unit's determination by directly appealing to FERC, in accordance with FERC's rules and procedures. In such case, the applicable Scheduling Coordinator shall also dispute the Preliminary Settlement Statement containing the financial penalty, in accordance with Section 11 of the ISO Tariff. The Preliminary Settlement Statement dispute and appeal to FERC must be made in accordance with the timeline for raising disputes specified in Section 11.7.2 of the ISO Tariff. The penalty will be tolled until FERC renders its decision on the appeal. The disposition by FERC of such appeal shall be final, and no separate dispute of such Sanction may be initiated under Section 13 of the ISO Tariff, except as provided in Section 37.9.3.4. For the purpose of applying the time limitations set forth in Section 37.10.1, a sanction will be considered assessed when it is included on a Preliminary Settlement Statement, whether or not the ISO accepts a Scheduling Coordinator's dispute of such Preliminary Settlement Statement pending resolution of an appeal to FERC in accordance with this section or Section 37.9.3.3.

37.9 Administration of Sanctions

37.9.1 Assessment; Waivers and Adjustments. Penalty amounts for violation of these Rules of Conduct shall be calculated as specified in Section 37.2 through Section 37.7. A Sanction specified in this Section 37 may be modified by FERC when it determines that such adjustment is just and reasonable. The ISO may make a recommendation to FERC to modify a Sanction. An adjustment generally shall be deemed appropriate if the prescribed Sanction appears to be insufficient to deter the prohibited behavior, or if the circumstances suggest that the violation was inadvertent, unintentional, or some other mitigating circumstances exist.

37.9.2 Excuse.

The following circumstances shall excuse a violation of a Rule of Conduct under the terms of this ISO Tariff:

37.9.2.1 Uncontrollable Force.

No failure by a Market Participant to satisfy the Rules of Conduct shall be subject to penalty to the extent and for the period that the Market Participant's inability to satisfy the Rules of Conduct is caused by an event or condition of Uncontrollable Force affecting the Market Participant; provided that the Market Participant gives notice to the ISO of the event or condition of Uncontrollable Force as promptly as possible after it knows of the event or condition and makes all reasonable efforts to cure, mitigate, or remedy the effects of the event or condition.

37.9.2.2 Safety, Licensing, or Other Requirements.

Failure by a Market Participant to perform its obligations shall not be subject to penalty if the Market Participant is able to demonstrate that it was acting in accordance with Section 4.2.1 of the ISO Tariff.

37.9.2.3 Emergencies.

Failure by a Market Participant to perform its obligations may not be subject to penalty if the Market Participant is able to demonstrate that it was acting in good faith and consistent with Good Utility Practice to preserve System Reliability in a System Emergency, unless contrary to an ISO operating order.

37.9.2.4 Conflicting Directives.

To the extent that any action or omission by a Market Participant is specifically required by a FERC Order or ISO operating order, the Market Participant may not be subject to penalty for that act or omission.

37.9.3 Settlement.

37.9.3.1 Settlement Statements.

The ISO will administer any penalties issued under this Enforcement Protocol through Preliminary Settlement Statements, and Final Settlement Statements issued to the responsible Scheduling Coordinator by the ISO. Before invoicing a financial penalty through the Settlement process, the ISO will provide a description of the penalty to the responsible Scheduling Coordinator and all Market Participants the Scheduling Coordinator represents that are liable for the penalty, when the ISO has sufficient objective information to identify and verify responsibility of such Market Participants. The ISO shall

specify whether such penalty is modified pursuant to Section 37.2.5, Section 37.4.4 or Section 37.9.1.

The description shall include the identity of the Market Participant that committed the violation and the amount of the penalty. Where FERC has determined the Sanction, the ISO will provide such of the above information as is provided to it by FERC. The ISO also may publish this information under the ISO Home Page after Final Settlement Statements are issued.

37.9.3.2 Payment.

Except as provided in Section 37.2.5, Section 37.4.4, Section 37.8.10 or Section 37.9.3.3 below, the Scheduling Coordinator shall be obligated to pay all penalty amounts reflected on the Preliminary and Final Settlement Statements to the ISO pursuant to the ISO's Settlement process, as set forth in Section 11 of the ISO Tariff.

37.9.3.3 Other Responsible Party.

Where a party or parties other than the Scheduling Coordinator is responsible for the conduct giving rise to a penalty reflected on a Preliminary or Final Settlement Statement, and where the Scheduling Coordinator bears no responsibility for the conduct, such other party or parties ultimately shall be liable for the penalty. Under such circumstances, the Scheduling Coordinator shall use reasonable efforts to obtain payment of the penalty from the responsible party(ies) and to remit such payment to the ISO in the ordinary course of the settlement process. In the event that the responsible party(ies) wish to dispute the penalty, or the Scheduling Coordinator otherwise is unable to obtain payment from the responsible parties, the Scheduling Coordinator shall notify the ISO and dispute the Preliminary Settlement Statement. The ISO promptly shall notify FERC. **If the ISO finds that a Market Participant separate from the Scheduling Coordinator that is unable to obtain payment from the responsible party(ies) is solely responsible for a violation, the Scheduling Coordinator that is unable to obtain payment may net its payment of its Invoice amount by the amount of the penalty in question.** The ISO may refuse to offer further service to any responsible party that fails to pay a penalty, unless excused under the terms of the Tariff or this Enforcement Protocol, by providing notice of such refusal to the Scheduling Coordinator. Following such notice, the Scheduling Coordinator shall be liable for any subsequent penalties assessed on account of such responsible party.

37.9.3.4 Dispute of FERC Sanctions.

The right that a Market Participant may otherwise have under the Tariff or this Enforcement Protocol to dispute a penalty that has been determined by FERC shall be limited to a claim that the ISO failed properly to implement the penalty or other Sanction ordered by FERC, except as provided by Section 37.2.5 and Section 37.4.4.

37.9.4 Disposition of Proceeds.

The ISO shall collect penalties assessed pursuant to this Section 37.9 and deposit such amounts in an interest bearing trust account. After the end of each calendar year, the ISO shall distribute the penalty amounts together with interest earned through payments to Scheduling Coordinators as provided herein. For the purpose of this Section 37.9.4, "eligible Market Participants" shall be those Market Participants that were not assessed a financial penalty pursuant to this Section 37 during the calendar year.

Each Scheduling Coordinator that paid GMC during the calendar year will identify, in a manner to be specified by the ISO, the amount of GMC paid by each Market Participant for whom that Scheduling Coordinator provided service during that calendar year. The total amount assigned to all Market Participants served by that Scheduling Coordinator in such calendar year (including the Scheduling Coordinator itself for services provided on its own behalf), shall equal the total GMC paid by that Scheduling Coordinator.

The ISO will calculate the payment due each Scheduling Coordinator based on the lesser of the GMC actually paid by all eligible Market Participants represented by that Scheduling Coordinator, or the product of a) the amount in the trust account, including interest, and b) the ratio of the GMC paid by each Scheduling Coordinator on behalf of eligible Market Participants, to the total of such amounts paid by all Scheduling Coordinators. Each Scheduling Coordinator is responsible for distributing payments to the eligible Market Participants it represented in proportion to GMC collected from each eligible Market Participant.

Prior to allocating the penalty proceeds, the ISO will obtain FERC's approval of its determination of eligible Market Participants and their respective shares of the trust account proceeds. If the total amount

in the trust account to be so allocated exceeds the total GMC obligation of all eligible Market Participants, then such excess shall be treated in accordance with Section 11.8.5.3(b).

37.10 Miscellaneous.

37.10.1 Time Limitation.

An investigation of events potentially subject to Sanction under this Section 37 must be commenced within 90 days of discovery of the events. Sanctions may be assessed under this Section 37 up to one year after discovery of the events constituting the violation, but no later than three years after the date of the violation. Nothing in this section shall limit the rights or liabilities of any party under any other provision of applicable laws, regulations or tariff provisions.

37.10.2 No Limitation on Other Rights.

Nothing contained in this Section 37 shall limit the ability of the ISO to collect information from Market Participants or to establish new provisions pursuant to Section 15 of the ISO Tariff.

37.11 Method for Calculating Penalties.

1. Method for Calculating Inaccurate Meter Data Penalty.

There is no Sanction for the submission of inaccurate meter data used for Preliminary Settlement Statements. However, an error in submitted meter data that is discovered after issuance of Final Settlement Statements constitutes a Rule of Conduct violation. The level of the Sanction depends on whether the Scheduling Coordinator or the ISO discovered the error. An increased penalty will apply for errors that are discovered by the ISO.

Table A1 below shows how the level of the Sanction depends on the following factors: whether or not the Scheduling Coordinator finds the error; whether or not the Scheduling Coordinator owes the market, and whether or not the ISO reruns settlement of the market. If the ISO reruns the market, then settlement to all Scheduling Coordinators is recalculated, and the impact of such reruns on charges assessed will be considered. A charge equal to 30% of the estimated value of the Energy error will apply if the Scheduling Coordinator discovers the error, or 75% of the estimated value of the Energy error if the ISO discovers

the error. Penalty assessment and disposition of penalty proceeds will be administered as described in Section 37.9.1 and Section 37.9.4 respectively. A Sanction will not be imposed unless such Sanction is more than \$1,000 for at least one Trading Day during the period for which there was incomplete or inaccurate meter data.

Table A1 – Calculation of Inaccurate Meter Data Penalty When There Is A Market Rerun

Case	Does SC Owe Market?	
Case 1: SC Identifies Inaccurate Meter Data	Yes	Charge = (MWh x Hourly Ex Post Price ¹) x 0.30
Case 1: SC Identifies Inaccurate Meter Data	No	Charge = (MWh x Hourly Ex Post Price ¹) x 0.30
Case 2: ISO Identifies Inaccurate Meter Data	Yes	Charge = (MWh x Hourly Ex Post Price ¹) x 0.75
Case 2: ISO Identifies Inaccurate Meter Data	No	Charge = (MWh x Hourly Ex Post Price ¹) x 0.75

Note to Table A1:

The applicable price will be the greater of the Hourly Ex Post Price or \$10/MWh. The Hourly Ex Post Price used will be the value posted under the ISO Home Page for each Trading Hour of the applicable Trading Day.

2. Method for Calculating Inaccurate Meter Data Penalty When The Market Is Not Re-Run.

If the Market is not re-run, for cases of inaccurate meter data, Table A2 will be used to determine and allocate the penalty proceeds. This method approximates the financial impact on the market; however, it does not completely reflect all the settlement consequences of inaccurately submitted meter data. This

will be considered a market adjustment. The approximated value of the inaccurate meter data in question will be calculated and returned to the Market based on the average of the pro rata share of Unaccounted For Energy (UFE) charged in the UDC territory during the period of the inaccurate meter data event. The 30% or 75% penalty will be distributed as discussed in Section 37.9.4. For cases where the market is not re-run and the Scheduling Coordinator does not owe the market, then no market adjustment will be performed.

TABLE A2- Calculation Of Inaccurate Meter Data Penalty When There Is No Market Re-Run

Case	Does SC Owe Market?	ISO does not perform a market settlement re-run
Case 1: SC Identifies Inaccurate Meter Data	Yes	Market Adjustment = (MWh x Hourly Ex Post Price ¹) Penalty = (MWh x Hourly Ex Post Price ¹) x 0.30
Case 1: SC Identifies Inaccurate Meter Data	No	No Market Adjustment will be made Penalty = (MWh x Hourly Ex Post Price ¹) x 0.30
Case 2: ISO Identifies Inaccurate Meter Data	Yes	Market Adjustment = (MWh x Hourly Ex Post Price ¹) Penalty = (MWh x Hourly Ex Post Price ¹) x 0.75
Case 2: ISO Identifies Inaccurate Meter Data	No	No Market Adjustment will be made Penalty = (MWh x Hourly Ex Post Price ¹) x 0.75

Notes to Table A2:

The applicable price will be the greater of the Hourly Ex Post Price or \$10/MWh. The Hourly Ex Post Price used will be the value posted under the ISO Home Page for each Trading Hour of the applicable Trading Day.

A Sanction will be imposed only if the Sanction is more than \$1,000 for at least one Trading Day during the period for which there was incomplete or inaccurate meter data.

If the error is to the detriment of the responsible Scheduling Coordinator (e.g., under-reported generation

or over-reported load), and the ISO does not rerun the market, then no correction will be made, representing an implicit penalty of 100% of the value of the Energy. If the market is rerun after the error is corrected, then the Scheduling Coordinator will be given credit for the additional Energy through the normal Settlement process. If the Scheduling Coordinator is paid for an error due to a market rerun, then a Sanction will be assessed to assure that market reruns do not diminish the incentive to correct such errors. This Sanction would be 30% of the Energy value of the error if the Scheduling Coordinator discovers the error, or 75% estimated value of the error if the ISO discovers the error.

If the error is to the detriment of the market, then a charge equal to 30% or 75% of the estimated value of the error, as appropriate, will be added to the charge for the Energy. If there is no market rerun, then the cost of Energy supplied by the ISO (and inappropriately charged to the market as Unaccounted for Energy) must be recovered as well, and the charge will be equal to 130% or 175% of the estimated value of the error, as appropriate.

ARTICLE IV – MARKET MONITORING AND MARKET POWER MITIGATION

38 MARKET MONITORING.

38.1 Objectives and Scope.

This Section sets forth the workplan and, where applicable, the rules under which the ISO Department of Market Analysis and ISO Market Surveillance Committee will monitor the ISO Markets to identify abuses of market power, to ensure to the extent possible the efficient working of the ISO Markets immediately upon commencement of their operation, and to provide for their protection from abuses of market power in both the short term and the long term, and from other abuses that have the potential to undermine their effective functioning or overall efficiency in accordance with Section 38.1.1 of the ISO Tariff. Such monitoring activities will be carried out by, among other ISO departments, the ISO Department of Market Analysis and the ISO Market Surveillance Committee to be established and to operate under the terms of this Protocol, as set forth below. These protocols provide a general framework for the operation of the Department of Market Analysis and the Market Surveillance Committee and are not intended to limit the activities or remedies available to these entities or to the ISO as a whole elsewhere in the ISO Tariff or otherwise under law.

38.1.1 Market Surveillance: Changes to Operating Rules and Protocols.

The ISO shall keep the operation of the markets that it administers under review to determine whether changes in its operating rules or ISO Protocols would improve the efficiency of those markets or prevent the exercise of market power by any Market Participant; and it shall institute necessary changes in accordance with this Section 38. The details of the ISO Market Monitoring and Information Protocol are set forth in Appendix P.

38.1.2 Reporting Requirements.

This Section of the ISO Tariff sets forth the information dissemination, publication and reporting activities and other means of providing information that the ISO generally undertakes to meet its reporting requirements to regulatory agencies, Market Participants and others. The goal of the reporting provisions is to adequately inform regulatory agencies, law enforcement agencies, policymakers, Market Participants and others of the state of the ISO Markets, especially their competitiveness and efficiency. This function is designed to facilitate efficient corrective actions to be taken by the appropriate body or bodies when required.

38.2 Practices Subject to Scrutiny – General.

The Department of Market Analysis shall monitor the activities of Market Participants that affect the operation of the ISO Markets and that provide indications of the phenomena set forth below in this Section 38.2. Where appropriate, it will take such further action as it considers necessary under Section 38.4.

38.2.1 Abuse of Reliability Must-Run Unit Status.

Where Generating Units are determined by the ISO to be Reliability Must-Run Units, circumstances that indicate that such Generating Units are being operated in a manner that will adversely affect the competitive nature and efficient workings of the ISO Markets.

38.2.2 ISO and Other Market Design Flaws.

Design flaws and inefficiencies in the ISO Tariff, ISO Protocols and operational rules and procedures of

the ISO, including the potential for problems between the ISO and other independent power markets or exchanges insofar as they affect the ISO Markets.

38.2.3 Market Structure Flaws.

With respect to flaws in the overall structure of the California energy markets that may reveal undue concentrations of market power in Generation or other structural flaws, the Department of Market Analysis shall provide such information or evidence of such flaws and such analysis as it may conduct to the ISO CEO and/or to the ISO Governing Board, subject to due protections of confidential or commercially sensitive information. After due internal consultation, if instructed by any of such ISO institutions or persons, the Department of Market Analysis shall also provide such information or evidence to the Market Surveillance Committee, the appropriate regulatory and antitrust enforcement agency or agencies, subject to due protections of confidential or commercially sensitive information. The Department of Market Analysis shall, at the direction of the ISO CEO and/or the ISO Governing Board, or their designee, provide such other evidence, views, analyses or testimony as may be appropriate or required and as it is reasonably capable of providing to assist the investigations of such agencies.

38.3 Scrutiny of Participant Changes Potentially Affecting Market Structure.

The Department of Market Analysis may undertake the following measures to monitor the special circumstances that may affect the operation of the ISO Markets due to corporate reorganizations including bankruptcies or changes in Affiliate relationships and may recommend corrective actions as provided in Section 38.4.

38.3.1 Exercises of Horizontal Market Power.

The Department of Market Analysis may analyze the impact of changes in market structure on the ability of Market Participants to exercise short-term horizontal market power.

38.4 Response Action by ISO.

38.4.1 Corrective Actions.

Where the monitoring activities or any consequent investigations carried out by the Department of Market 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 Service 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 Incremental Energy Bids.

Negative incremental 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 Applicability.

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 (hereinafter 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 September 30th 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. Scheduling Coordinators representing a Load Serving Entity that has proposed a Planning Reserve Margin to, and is pending consideration by, the CPUC or other Local Regulatory Authority, the Planning Reserve Margin shall be that pending before the CPUC or other Local Regulatory Authority.
- d. For Scheduling Coordinators representing a Load Serving Entity that has not proposed a Planning Reserve Margin to the CPUC or other Local Regulatory Authority or the CPUC or other Local Regulatory Authority has not established a Planning Reserve Margin, the Planning Reserve Margin shall be 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.

To the extent the CPUC or other Local Regulatory Authority has not established for a particular Load Serving Entity 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 at the time the Load Serving Entity must submit a Resource Adequacy Plan, 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 where such criteria has been proposed by the Load Serving Entity and is pending before the CPUC or applicable Local Regulatory Authority. Only if criteria for determining the types of resources that may be eligible to provide Qualifying Capacity and for calculating Qualifying Capacity from eligible resource types has not been provided by the CPUC or other Local Regulatory Authority or Load Serving Entity as provided for in this Section, then Section 40.13 will apply. The ISO shall use the criteria provided by the CPUC, other Local Regulatory Authority, or Load Serving Entity 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 annual deliverability analysis shall be effective for a period no shorter than the entire next calendar year. 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.

40.5.2.2.1 Available Import Capability Assignment Process.

For Resource Adequacy Plans covering any period after December 31, 2007, total Available Import Capability will be assigned on an annual basis for a one-year term to Load Serving Entities serving Load in the ISO Control Area and other Market Participants through their respective Scheduling Coordinators, as described by the following sequence of steps. However, should the CPUC modify by decision its compliance period from January to December of the calendar year to May through April of the calendar year, the CAISO shall extend the effectiveness of the assignment for 2009 Compliance Year through April 2010.

Step 1: Determination of Maximum Import Capability on Branch Groups into the ISO Control Area:

The ISO shall establish the Maximum Import Capability for each branch group into the ISO Control Area, and will post those values on the ISO website for RA Compliance Year 2009 by July 1, 2008, and for subsequent RA Compliance Years in accordance with the schedule and process set forth in the business practice manual.

Step 2: Determination of Available Import Capability by Accounting for Existing Contracts and

Transmission Ownership Rights Held by Out-of-ISO Control Area LSEs: For each branch group, the Available Import Capability will be determined by subtracting from the Maximum Import Capability established in Step 1 for each branch group the import capability on each branch group associated with (i) Existing Contracts and (ii) Transmission Ownership Rights held by load serving entities that do not serve Load within the ISO Control Area. The remaining sum of all branch group Available Import Capability is the Total Import Capability. Total Import Capability shall be used to determine the Load Share Quantity for each Load Serving Entity that serves Load within the ISO Control Area.

Step 3: Determination of Existing Contract Import Capability by Accounting for Existing Contracts and Transmission Ownership Rights Held by In-ISO Control Area LSEs: From the Available Import Capability remaining on each branch group after Step 2 above, Existing Contracts and Transmission Ownership Rights held by Load Serving Entities that serve Load within the ISO Control Area shall be reserved for the holders of such commitments and will not be subject to reduction under any subsequent steps in this Section. The import capability reserved pursuant to this Step 3 is the Existing Contract Import Capability.

Step 4: Assignment of Pre-RA Import Commitments: From the Available Import Capability remaining on each branch group after reserving Existing Contract Import Capability under Step 3 above, the ISO will assign to Load Serving Entities serving Load within the ISO Control Area Pre-RA Import Commitment Capability on a particular branch group based on Pre-RA Import Commitments in effect (where a supplier has an obligation to deliver the Energy or make the capacity available) at any time during the RA Compliance Year for which the Available Import Capability assignment is being performed. The Pre-RA Import Commitment will be assigned to the branch group selected by the Load Serving Entity during the RA Compliance Year 2007 import capability assignment process, which was required to be based on the branch group upon which the Energy or capacity from the Pre-RA Import Commitment had been primarily scheduled or, for a Pre-RA Import Commitment without a scheduling history at the time of the RA Compliance Year 2007 import capability assignment process, the primary branch group upon which the Energy or capacity was anticipated to be scheduled. To the extent a Pre-RA Import Commitment was not presented during the RA Compliance Year 2007 import capability assignment process, the Load Serving Entity shall select the branch group upon which the Pre-RA Import Commitment is primarily anticipated to be scheduled during the term of the Pre-RA Import Commitment and that selection shall be utilized in future annual Available Import Capability assignment processes.

To the extent a particular branch group becomes over requested with Pre-RA Import Commitments due to either Pre-RA Import Commitments not included in the RA Compliance Year 2007 import capability assignment process or changes in system conditions that decrease the Maximum Import

Capability of the branch group, such that the MW represented in all Pre-RA Import Commitments utilizing the branch group exceed the branch group's Available Import Capability in excess of that reserved for Existing Contracts and Transmission Ownership Rights under Steps 2 and 3, the Pre-RA Import Commitments will be assigned Pre-RA Import Commitment Capability, based on the Import Capability Load Share Ratio of each Load Serving Entity submitting Pre-RA Import Commitments on the particular branch group. To the extent this initial assignment of Pre-RA Import Commitment Capability has not fully assigned the Available Import Capability of the particular over requested branch

group, the remaining Available Import Capability on the over requested branch group will be assigned until fully exhausted based on the Import Capability Load Share Ratio of each Load Serving Entity whose submitted Pre-RA Import Commitment has not been fully satisfied by the previous Import Capability Load Share Ratio assignment iteration. The Available Import Capability assigned pursuant to this Step 4 is the Pre-RA Import Commitment Capability.

Step 5: Assignment of Remaining Import Capability Limited by Load Share Quantity: The Total Import Capability remaining after Step 4 will be assigned only to Load Serving Entities serving Load within the ISO Control Area that have not received Existing Contract Import Capability and Pre-RA Import Commitment Capability under Steps 3 and 4, that exceed the Load Serving Entity's Load Share Quantity. This Total Import Capability will be assigned until fully exhausted to those Load Serving Entities eligible to receive an assignment under this Step based on each Load Serving Entity's Import Capability Load Share Ratio up to, but not in excess of, its Load Share Quantity. The quantity of Total Import Capability assigned to the Load Serving Entity under this Step is the Load Serving Entity's Remaining Import Capability. This Step 5 does not assign Remaining Import Capability on a specific branch group.

Step 6: ISO Posting of Assigned and Unassigned Capability: Following the completion of Step 5, the ISO will post to its website for RA Compliance Year 2009 by July 9, 2008 and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual the following information:

- a. The Total Import Capability;
- b. The quantity in MW of Existing Contracts and Transmission Ownership Rights assigned to each branch group, distinguishing between Existing Contracts and Transmission Ownership Rights held by Load Serving Entities within the ISO Control Area and those held by load serving entities outside the ISO Control Area;

- c. The aggregate quantity in MW, and identify the holders, of Pre-RA Import Commitments assigned to each branch group; and
- d. The aggregate quantity in MW of Available Import Capability after Step 4, the identity of the branch groups with Available Import Capability, and the MW quantity of Available Import Capability on each such branch group.

Step 7: ISO Notification of LSE Assignment Information: Following the completion of Step 5, by July 9, 2008 for RA Compliance Year 2009 and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual, the ISO will notify the Scheduling Coordinator for each Load Serving Entity of:

- a. The Load Serving Entity's Import Capability Load Share;
- b. The Load Serving Entity's Load Share Quantity; and
- c. The amount of, and branch group on which, the Load Serving Entity's Existing Contract Import Capability and Pre-RA Import Commitment Capability, as applicable, has been assigned; and
- d. The Load Serving Entity's Remaining Import Capability.

Step 8: Transfer of Import Capability: Up to and including July 17, 2008 for RA Compliance Year 2009 and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual, a Load Serving Entity shall be allowed to transfer some or all of its Remaining Import Capability to any other Load Serving Entity or Market Participant. The ISO will accept transfers among

LSEs and Market Participants only to the extent such transfers are reported to the ISO by July 18,

2008 for RA Compliance Year 2009 and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual through the ISO's Import Capability Transfer Registration Process by the entity receiving the Remaining Import Capability that sets forth (1) the name of the counter-parties, (2) the MW quantity, (3) term of transfer, and (4) price on a per MW basis. The CAISO will post to its website by August 8, 2008 for RA Compliance Year 2009 and for subsequent RA Compliance Years in accordance with the schedule set forth in the Business Practice Manual the information on transfers of Remaining Import Capability Received under this Step 8.

Step 9: Initial Scheduling Coordinator Request to Assign Remaining Import Capability by Branch

Group: At any time up to and including July 19, 2008 for RA Compliance Year 2009 and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual, the Scheduling Coordinator for each Load Serving Entity or Market Participant shall notify the ISO of its request to assign its post-trading Remaining Import Capability on a MW basis per available branch group. Total requests for assignment of Remaining Import Capability by a Scheduling Coordinator cannot exceed the sum of the post-traded Remaining Import Capability of its Load Serving Entities. 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 Remaining Import Capability on that branch group will be assigned based on each Load Serving Entity's Import Capability Load Share Ration in the same manner as set forth in Step 4. A Market Participant without an Import Capability Load Share will be assigned the Import Capability Load Share equal to the average Import Capability Load Share of those Load Serving Entities from which it received transfers of Remaining Import Capability.

Step 10: ISO Notification of Initial Remaining Import Capability Assignments and Unassigned

Capability: At any time up to and including July 27, 2008 for RA Compliance Year 2009 and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual, the ISO will:

- a. Notify the Scheduling Coordinator for each Load Serving Entity or Market Participant of the Load Serving Entity or Market Participant's accepted request(s) for assigning Remaining Import Capability under Step 9; and

- b. Publish on its website aggregate unassigned Available Import Capability, if any, the identity of the branch groups with unassigned Available Import Capability, and the MW quantity of Available Import Capability, on each such branch group.

Step 11: Secondary Scheduling Coordinator Request to Assign Remaining Import Capability by

Branch Group: To the extent Remaining Import Capability remains unassigned as disclosed by Step 10, at any time up to and including August 1, 2008 for RA Compliance Year 2009 and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual, Scheduling Coordinators for Load Serving Entities or Market Participants shall notify the ISO of their requests to assign any remaining Remaining Import Capability 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 assigned based on each Load Serving Entity or Market Participant's Import Capability Load Share Ratio, as used in Steps 4 and 9.

Step 12: Notification of Secondary Remaining Import Capability Assignments and Unassigned

Capability: At any time up to and including August 8, 2008 for RA Compliance Year 2009 and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual, the ISO will:

- a. Notify the Scheduling Coordinator for each Load Serving Entity or Market Participant of the Load Serving Entity or Market Participant's accepted request(s) for assigning Remaining Import Capability under Step 11; and
- b. Publish on its website unassigned aggregate Available Import Capability, if any, the identity of the branch groups with Available Remaining Import Capability, and the MW quantity of Availability Import Capability on each such branch group.

Step 13: Requests for Balance of Year Unassigned Available Import Capability: To the extent total Available Import Capability remains unassigned as disclosed by Step 12, Scheduling Coordinators for Load Serving Entities or Market Participants shall notify the ISO at any time, except as limited herein, of a request for unassigned Available Import Capability on a specific branch group on a per MW basis. Each request must include the identity of Load Serving Entity or Market Participant on whose behalf the request is made. The ISO will accept only two (2) requests per calendar week from any Scheduling Coordinator on behalf of a single Load Serving Entity or other Market Participant. The ISO will honor requests in priority of the time requests from Scheduling Coordinators were received until the branch group is fully assigned and without regard to any Load Serving Entity's Load Share Quantity. Any honored request shall be for the remainder of the RA Compliance Year; however, any notification by the ISO of acceptance of the request in accordance with this Section after the 20th calendar day of any month shall not be permitted to be included in the Load Serving Entity's Resource Adequacy Plan submitted in the same month as the acceptance.

The ISO shall provide an electronic means, either through the Import Capability Transfer Registration Process or otherwise, of notifying the Scheduling Coordinator of the time the request was deemed received by the ISO and, within seven (7) days of receipt of the request, whether the request was honored. If honored, it shall be the responsibility of the Scheduling Coordinator and its Load Serving Entity to notify the CPUC or applicable Local Regulatory Authority of the acceptance of the request for unassigned import capability. If the request is not honored because the branch group requested was fully assigned, the request will be deemed rejected and the Scheduling Coordinator, if it still seeks to obtain unassigned Available Import Capability, will be required to submit a new request for unassigned import capability on a different branch group. For RA Compliance Year 2009, the ISO will update on its website the list of unassigned capability by branch group on or before the 5th calendar day of each month and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual.

This multi-step process for assignment of Total Import Capability does not guarantee or result in any actual transmission service being assigned and is only used for determining the import capability 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 Pre-RA Import Commitments and any transfers or sales of assigned Total Import Capability. To the extent that the ISO's review of Resource Adequacy Plans identifies reliance upon Total Import Capability that exceeds the Total Import Capability assigned to the Load Serving Entity under this section, the ISO will inform the CPUC or appropriate Local Regulatory Authority, as appropriate.

40.5.2.2.2 Bilateral Import Capability Transfers and Registration Process

40.5.2.2.2.1 Eligibility Registration for Bilateral Import Capability Transfers

To be eligible to engage in any bilateral assignment, sale, or other transfer of Remaining Import Capability under Step 8 of Section 40.5.2.2.1 or Section 40.5.2.2.2.2 or Existing Contract Import Capability, and Pre-RA Import Commitment Capability under Section 40.5.2.2.2.2, a Load Serving Entity or other Market Participant must provide the ISO through the Import Capability Transfer Registration Process the following information:

- a. Name of the Load Serving Entity or Market Participant
- b. E-mail contact information

For RA Compliance Year 2008, beginning in July 2007, the ISO will post to its website the information received under this Section on a monthly basis on or before the 5th calendar day of each month and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual. Any assignment, sale, or other transfer of Existing Contract Import Capability, Pre-RA Import Commitment Capability or Remaining Import Capability may only be made by or to a Load Serving Entity or Market Participant whose information received under this Section has been posted to the ISO website prior to the date of the assignment sale or other transfer of the Existing Contract Import Capability, Pre-RA Import Commitment Capability or Remaining Import Capability. It shall be the exclusive responsibility of the Load Serving Entity or Market Participant to ensure that the information posted to the ISO website under this Section is accurate and up to date.

40.5.2.2.2 Reporting Process for Bilateral Import Capability Transfers

This Section shall apply to all transfers of Existing Contract Import Capability, Pre-RA Import Commitment Capability or Remaining Import Capability other than that provided for in Step 8 of Section 40.5.2.2.1.

Any Load Serving Entity or other Market Participant that has obtained Existing Contract Import Capability, Pre-RA Import Commitment Capability or Remaining Import Capability may assign, sell, or otherwise transfer such Existing Contract Import Capability, Pre-RA Import Commitment Capability or Remaining Import Capability in MW increments. The import capability subject to each transfer shall remain on the branch group assigned pursuant to Section 40.5.2.2.1.

The Scheduling Coordinator for the Load Serving Entity or Market Participant receiving the transferred Existing Contract Import Capability, Pre-RA Import Commitment Capability or Remaining Import Capability must report the transfer to the ISO through the ISO's Import Capability Transfer Registration Process by providing the following information:

- a. Identity of the counter-party(ies);
- b. The MW quantity;
- c. The branch group on which the Existing Contract Import Capability, Pre-RA Import Commitment Capability or Remaining Import Capability was assigned;
- d. The term of the transfer;
- e. Price on a per MW basis; and
- f. Whether the import capability assignment being transferred is Existing Contract Import Capability, Per-RA Import Commitment Capability, or Remaining Import Capability.

The ISO will promptly post to its website the information on transfers of received under the Section except for the information received pursuant to subpart f of this section. On a quarterly basis, the ISO shall also report to FERC the transfer information received under this Section and Step 8 of Section 40.5.2.2.1.

Transfer information received in accordance with this Section after the 20th calendar day of any month shall not be permitted to be included in the Load Serving Entity's Resource Adequacy Plan submitted in the same month as the transfer submission.

40.5.2.2.2.3 Other Import Capability Information Postings

For RA Compliance Year 2008, beginning in September 2007, the ISO will post to its website on a monthly basis on or before the 5th calendar day of each month and for subsequent RA Compliance Years in accordance with the schedule set forth in the business practice manual, for each branch group, the holder and that holder's quantity in MW of import capability assigned on the particular branch group as of the reporting date.

The ISO will also post to its website following submission of the annual Resource Adequacy Plans under Sections 40.2.1.1, 40.2.2.4, 40.2.3.4, and 40.2.4, for each branch group, by a "yes" or "no" designation, whether each holder of import capability assigned on the particular branch group has fully included the assigned import capability in the holder's annual Resource Adequacy Plans.

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 (per the requirements set forth in Section 9.3.10.2), Uncontrollable Force 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 **or resources designated under the TCPM**, and then, if permissible, the ISO may grant waivers to Resource Adequacy Resources or resources designated as **TCPM** 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). To the extent conditions permit, the ISO will revoke the waivers of Resource Adequacy Resources and **TCPM** resources prior to revoking the waivers of FERC Must-Offer Generators. 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 whether 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 reliability requirements, or (3) ISO Control Area-wide reliability requirements pursuant to Section 40.6B.5.1. On a monthly basis, 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 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. 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 to meet zonal reliability requirements, 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 Coordinators' 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 meet ISO Control Area-wide reliability requirements, 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, except that Demand outside the ISO Control Area that is served by exports that are scheduled as part of a Wheeling Through transaction shall be excluded from the calculation of such allocations.

40.6B.5.1 Criteria for Allocation of Un-Recovered Minimum Load Costs

The ISO shall use the following criteria for determining whether a Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity falls within the local reliability, zonal reliability, or ISO Control Area-wide reliability categories for allocation of Un-Recovered Minimum Load Costs.

40.6B.5.1.1 Local Reliability Requirements

The ISO shall classify a Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity as committed or operated for local reliability requirements when it is committed or operating to:

- (1) maintain power flows on a transmission component that is not part of a transmission path between Congestion Zones;
- (2) maintain acceptable voltage levels at a network location that is not part of a transmission path between Congestion Zones; or
- (3) accommodate the forced or scheduled outage of a network component that is not part of a transmission path between Congestion Zones.

40.6B.5.1.2 Zonal Reliability Requirements

The ISO shall classify a Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity as committed or operated for zonal reliability requirements when it is committed or operating to:

- (1) maintain operations within the requirements of any nomogram that governs the operations of an Inter-Zonal Interface;
- (2) maintain power flows on a transmission line that is part of a transmission path between Congestion Zones or an Inter-Zonal Interface;
- (3) maintain acceptable voltage levels at a location that is part of a transmission path between Congestion Zones or an Inter-Zonal Interface; or
- (4) accommodate the forced or scheduled outage of a network component that is part of a transmission path between Congestion Zones or an Inter-Zonal Interface.
- (5) ensure there is sufficient capacity available to meet Operating Reserve requirements within a particular Zone, if the ISO is procuring Operating Reserve on a zonal basis.

40.6B.5.1.3 ISO Control Area-wide Reliability Requirements

The ISO shall classify a Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity as committed or operated for ISO Control Area-wide reliability requirements when it is committed or operating to meet forecast Control Area Demand or committed to ensure sufficient capacity is available to meet Operating Reserve requirements, when the ISO is not procuring Operating Reserve on a zonal basis.

40.6B.5.1.4 Incremental Cost of Local

Beginning October 1, 2004, when a Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity is committed for local reliability requirements, and that unit also meets an overall ISO Control Area-wide need, the ISO shall allocate only the incremental cost of committing that unit above the cost of committing the least-cost unit that would have been committed to resolve the ISO Control Area-wide reliability need absent the local reliability need, to the Participating TO.

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”, provided that such person with Eligible Capacity designated as **TCPM Capacity** shall not be considered a FERC Must-Offer Generator to the extent, and for the term, of the **TCPM Capacity** designation. 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 **or resources designated under the TCPM** and then, if permissible, the ISO may grant waivers to Resource Adequacy Resources or resources designated as **TCPM** 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 and **TCPM** 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 whether 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 reliability requirements, or (3) ISO Control Area-wide reliability requirements pursuant to Section 40.8.6.1. On a monthly basis, 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 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. Costs allocated under this part (1) shall be considered Reliability Services Costs.
- (2) if the Generating Unit was operating to meet zonal reliability 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 Coordinators' monthly Demand in that Zone;
- (3) if the Generating Unit was operating to meet ISO Control Area-wide reliability requirements, 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, except that Demand outside the ISO Control Area that is served by exports that are scheduled as part of a Wheeling Through transaction shall be excluded from the calculation of such allocations.

40.8.6.1 FERC Must Offer Generator Unit Criteria for Allocation of Minimum Load Costs

The ISO shall use the following criteria for determining whether a FERC Must Offer Generator unit falls within the local reliability, zonal reliability or ISO Control Area-wide reliability categories for allocation of Minimum Load Costs.

40.8.6.1.1 Local Reliability Requirements

The ISO shall classify a FERC Must Offer Generator unit as committed or operated for local reliability requirements when it is committed or operating to:

- (1) maintain power flows on a transmission component that is not part of a transmission path between Congestion Zones;
- (2) maintain acceptable voltage levels at a network location that is not part of a transmission path between Congestion Zones; or
- (3) accommodate the forced or scheduled outage of a network component that is not part of a transmission path between Congestion Zones.

40.8.6.1.2 Zonal Reliability Requirements

The ISO shall classify a FERC Must Offer Generator unit as committed or operated for zonal reliability requirements when it is committed or operating to:

- (1) maintain operations within the requirements of any nomogram that governs the operations of an Inter-Zonal Interface;
- (2) maintain power flows on a transmission line that is part of a transmission path between Congestion Zones or an Inter-Zonal Interface;
- (3) maintain acceptable voltage levels at a location that is part of a transmission path between Congestion Zones or an Inter-Zonal Interface; or
- (4) accommodate the forced or scheduled outage of a network component that is part of a transmission path between Congestion Zones or an Inter-Zonal Interface.
- (5) ensure there is sufficient capacity available to meet Operating Reserve requirements within a particular Zone, if the ISO is procuring Operating Reserve on a zonal basis.

40.8.6.1.3 ISO Control Area-wide Reliability Requirements

The ISO shall classify a FERC Must Offer Generator unit as committed or operated for ISO Control Area-wide reliability requirements when it is committed or operating to meet forecast Control Area Demand or committed to ensure sufficient capacity is available to meet Operating Reserve requirements, when the ISO is not procuring Operating Reserve on a zonal basis.

40.8.6.1.4 Incremental Cost of Local

Beginning October 1, 2004, when a FERC Must Offer Generator unit is committed for local reliability requirements, and that unit also meets an overall ISO Control Area-wide need, the ISO shall allocate only the incremental cost of committing that unit above the cost of committing the least-cost unit that would have been committed to resolve the ISO Control Area-wide reliability need absent the local reliability need, to the Participating TO.

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, in two parts: 1) All Emission Costs

attributed to minimum load Energy will be allocated to Scheduling Coordinators in proportion to and in a similar manner as each Scheduling Coordinator's Minimum Load Cost obligation per Section 40.8.6.1 or Un-Recovered Minimum Load Cost obligation under Section 40.6B.5.1. The amount of Emissions Costs attributed to minimum load Energy will be determined by dividing the total megawatt hours eligible for Minimum Load Cost compensation for the month by the total megawatt hours of Instructed Imbalance Energy for the month. The resulting percentage is then multiplied by the Emissions Cost Charges for the month to determine the Emission Costs attributed to minimum load Energy. The proportion of Emissions Costs to Minimum Load Costs will be determined by dividing the total Emissions Costs attributed to minimum load Energy for the month by the total Minimum Load Costs for the month. 2) All Emission Costs resulting from an ISO dispatch but not attributable to minimum load Energy will be allocated to 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 Emissions Cost Charge.

The amount the ISO will assess for the Emissions Cost Charge shall be 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 twelve (12) months. The initial amount for the Emissions Cost Charge, and all subsequent amounts for the Emissions Cost Charge, shall be posted on the ISO Website.

40.11.4 Adjustment of the Emissions Cost Charge.

The ISO may adjust the amount the ISO will assess for 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 amount the ISO will assess for 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 amount shall be assessed.

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 in proportion to and in a similar manner as each Scheduling Coordinator's Minimum Load Cost obligation under Section 40.8.6.1 or Un-Recovered Minimum Load Cost obligation under Section 40.6B.5.1. The proportion of Start-Up Costs to Minimum Load Costs will be determined by dividing the total Start-Up Cost Charge for the month by the total Minimum Load Costs for the month. The proportion of Start-Up Costs then will be multiplied by the individual Scheduling Coordinator's Minimum Load Costs for the month to determine the Scheduling Coordinator's Start-Up Cost Charge. 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 Start-Up Cost Charge.

The amount the ISO will assess for the Start-Up Cost Charge shall be the projected annual total of all Start-Up Costs incurred by Resource Adequacy Resources 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 twelve (12) months.

The initial amount for the Start-Up Cost Charge, and all subsequent amounts for the Start-Up Cost Charge, shall be posted on the ISO Website.

40.12.4 Adjustment of the Start-Up Cost Charge.

The ISO may adjust the amount the ISO will assess for 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 the projections of the Start-Up Costs incurred by Resource Adequacy Resources or FERC Must-Offer Generators as a direct result of ISO Dispatch Instructions and the actual Start-Up 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 40.12; and
- (b) the difference, if any, between actual and projected interest earned on funds in the Start-Up Cost Trust Account.

The adjusted amount the ISO will assess for 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 amount shall be assessed.

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.

40.14 Capacity Payments Under the FERC Must-Offer Obligation.

As set forth in this Section, Generating Units of FERC Must-Offer Generators that are eligible to recover Minimum Load Costs pursuant to Section 40.8 shall also be eligible to recover a Must-Offer Capacity Payment during Waiver Denial Periods, in addition to such Minimum Load Costs, provided the Generating Unit does not have an RMR contract, is not a Resource Adequacy Resource and is not designated as **TCPM**. The Must-Offer Capacity Payment shall equal $1/6^{\text{th}}$ of the Monthly **TCPM** Charge as specified in Schedule 6 of Appendix F per megawatt for each day of the Waiver Denial Period, adjusted pro rata for any hours of that day in which the Generating Unit was ineligible for the recovery of Minimum Load Costs. For any Trading Day of a calendar month, if the sum of (i) total Must-Offer Capacity Payments that a FERC Must-Offer Generator has received for a Generating Unit under this Section 43.14 during that month, (ii) the total Imbalance Energy payments received when that Generating Unit is running at minimum load, and (iii) the Frequently Mitigated Adder under Section 34.1.2.1.1 during the calendar month, exceeds the Qualifying Capacity times the maximum Monthly **TCPM** Charge (established in Schedule 6 of Appendix F) reduced by the Monthly PER (established in Schedule 6 of Appendix F), the FERC Must-Offer Generator shall not be eligible to receive Must-Offer Capacity Payments or the Frequently Mitigated Adder under Section 34.1.2.1.1 for that Generating Unit for that Trading Day, nor for any other Trading Day in the remainder of the calendar month (but shall continue to recover Minimum Load Costs and imbalance Energy payments). ***If a FERC Must-Offer Generator (i) has been denied one or more must-offer waiver(s) for any Trading Day(s) of a calendar month for a Generating Unit, (ii) is eligible for a Must-Offer Capacity Payment for such Trading Day(s), and (iii) the Generating Unit is either subsequently or previously designated as TCPM Capacity within that calendar month pursuant to Section 43.4, the total compensation that the FERC Must-Offer Generator shall receive for that calendar month***

from the combination of Must-Offer Capacity Payments, a TCPM Capacity Payment, the Frequently Mitigated Adder pursuant to Section 34.1.2.1.1, and the total Imbalance Energy payments received when that Generating Unit is operating at minimum load, shall be limited to the Qualifying Capacity of the FERC Must-Offer Generator's Generating Unit times the maximum Monthly TCPM Charge (established in Schedule 6 of Appendix F) reduced by the Monthly PER (established in Schedule 6 of Appendix F). This Section 40.14 shall expire at midnight on the **e** day before the MRTU Tariff goes into effect.

40.14.1 Allocation of Must-Offer Capacity Payments

The ISO shall determine whether the Must-Offer Capacity Payment costs for each FERC Must-Offer Generator Generating 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 month, the ISO shall sum the Must-Offer Capacity Payments costs and shall allocate those costs as follows:

- (1) if the Generating Unit was operating to meet local reliability requirements, the Must-Offer Capacity Payment costs shall be considered incremental locational costs and shall be allocated in accordance with Section 40.8.6 (1).
- (2) if the Generating Unit was operating due to Zonal requirements, the Must-Offer Capacity Payment costs shall be allocated in accordance with Section 40.8.6 (2)
- (3) if the Generating Unit was operating to satisfy an ISO Control Area-wide need, the Must-Offer Capacity Payment costs shall be allocated in accordance with Section 40.8.6 (3).

40.15 Must-Offer Reporting Requirements

Sections 40.15 through 40.15.4 shall expire at midnight on the day before the MRTU Tariff goes into effect.

40.15.1 Must-Offer Waiver Denial Report

The ISO shall publish a Must-Offer Waiver Denial Report ("MOWD Report") on the ISO Website on a weekly basis and shall provide a market notice of its availability. The MOWD Report shall indicate the category of the must-offer waiver denial, *i.e.*, local, zonal or system, and the amount of megawatts involved in each category. On a daily basis, thirty (30) days after the Trade Day, the ISO will publish on OASIS the allocation of Un-Recovered Minimum Load Costs for **TCPM** and Resource Adequacy Resources and Minimum Load Costs for FERC Must-Offer Generators.

40.15.2 Monthly Minimum Load Cost Report

On a monthly basis, thirty (30) days after the Trade Day, the ISO will publish on ISO Website, the monthly allocation of Un-Recovered Minimum Load Costs for **TCPM** and Resource Adequacy Resources, Minimum Load Costs for FERC Must-Offer Generators.

40.15.3 Multiple Denial of FERC Must-Offer Waivers

If the ISO issues a denial of must-offer waivers to a FERC Must-Offer Generator on four separate days in any calendar year, the ISO shall evaluate whether a **TCPM** Significant Event has occurred that warrants designation of the FERC Must-Offer Generator to provide service under the **TCPM** ("MOWD Evaluation").

The ISO shall conduct a MOWD Evaluation after every four separate days on which the ISO denies a must-offer waiver request for such a FERC Must-Offer Generator.

40.15.4 TCPM Significant Event/Repeat Waiver Denial Report

The ISO shall publish the results of its assessment of the MOWD Evaluation (“TCPM Significant Event/Repeat MOWD Report”), including an explanation of its decision whether to designate FERC Must-Offer Generator capacity as TCPM, on the ISO Website on a weekly basis unless no TCPM Significant Events or MOWD Evaluations occurred during the week. The ISO will provide a market notice of the availability of each TCPM Significant Event/Repeat MOWD Report. The TCPM Significant Event/Repeat MOWD Report shall explain why the ISO denied the must-offer waiver request that triggered the assessment of whether a TCPM Significant Event occurred, and whether any Resource Adequacy Resources, RMR units, or resources designated to provide service under the TCPM were available and called upon by the ISO prior to its denial of the FERC Must-Offer Generator’s must-offer waiver request. The ISO shall also explain why Non-Generation Solutions were insufficient to prevent the use of denials of must-offer waivers for local reasons. In the event that the ISO denies a must-offer waiver request for local or system reasons that do not constitute a TCPM Significant Event or is not due to a Resource Adequacy Resource non-performance, the report shall include an explanation for such issuance and shall be signed by the ISO’s Vice President of Operations.

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.

43 **Transitional Capacity Procurement Mechanism**

This section 43 of the ISO Tariff shall be referred to as the **Transitional Capacity Procurement Mechanism (TCPM)**. *The provisions of the TCPM supersede the provisions of the Reliability Capacity Services Tariff, except with respect to the provisions concerning payment and cost allocation to the extent necessary to determine any final payments and charges for service conducted under the Reliability Capacity Services Tariff.* The **TCPM** shall expire at midnight on the day before the MRTU Tariff goes into effect except that the provisions concerning compensation, cost allocation and settlement shall remain in effect until such time as **TCPM** resources have been finally compensated for their services rendered under the **TCPM** prior to the termination of the **TCPM**, and the ISO has finally allocated and recovered the costs associated with such **TCPM** compensation.

43.1 Designation

The ISO shall have the authority provided in this Section 43 to designate Eligible Capacity or System Resources to provide services under the **TCPM** as set forth in this Section 43.

43.2 Local TCPM Designations

The ISO may designate Eligible Capacity to provide services under the **TCPM** to meet local reliability needs to the extent provided in this Section 43.2.

43.2.1 **[NOT USED]**

43.2.1.1 **[NOT USED]**

43.2.1.2 **[NOT USED]**

43.2.1.3 Local TCPM Designations for Deficiencies

Following the ISO's identification of any Local Resource Adequacy Requirement Deficiency, the ISO may designate Eligible Capacity to provide services under the TCPM consistent with the criteria set forth in Section 43.2.2. The ISO may designate Eligible Capacity to provide service under this Section 43.2.1.3 to the extent necessary to satisfy any remaining Local Resource Adequacy Deficiency only after: (i) RMR Units have been designated in the local area reliability study process, and (ii) completion of the evaluation process set forth in Section 40.7 of Appendix CC. Designations

of Eligible Capacity to provide services under the **TCPM** made pursuant to this section shall have a *minimum commitment term of one (1) month and a maximum commitment term of one (1) year, based on the period(s) of overall shortage as reflected in the annual Resource Adequacy Plans that have been submitted, provided that the term of the designation may not extend into a subsequent Resource Adequacy Compliance Year and no term shall go beyond midnight on the day before the MRTU Tariff goes into effect.*

43.2.1.4 Collective Deficiency in Local Capacity Area Resources

The ISO shall have the authority to designate Eligible Capacity where the Local Capacity Area Resources specified in the annual Resource Adequacy Plans of all applicable Scheduling Coordinators, after the opportunity to cure under Section 43.2.1.4.1 has been exhausted, fail to ensure compliance in one or more Local Capacity Areas with the Local Capacity Technical Study criteria provided in Section 40.3.1.1 of Appendix CC. The ISO shall have the authority under this Section 43.2.1.4, regardless of whether such resources satisfy, for the deficient Local Capacity Area, the minimum amount of Local Capacity Area Resources identified in the Local Capacity Technical Study, but only after assessing the effectiveness of Generating Units under RMR Contracts, if any, and all Resource Adequacy Resources reflected in all submitted annual Resource Adequacy Plans, whether or not such Generating Units under RMR Contracts and Resource Adequacy Resources are located in the applicable Local Capacity Area. The ISO may, pursuant to this Section 43.2.1.4, designate Eligible Capacity in an amount and location sufficient to ensure compliance with the Reliability Criteria applied in the Local Capacity Technical Study. Eligible Capacity designated under this Section shall have a minimum commitment term of one (1) month and a maximum commitment term of one year, based on the period(s) of overall shortage as reflected in the annual Resource Adequacy Plans that have been submitted. The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year. Moreover, no term shall go beyond midnight on the day preceding the implementation of the MRTU Tariff.

43.2.1.4.1 LSE Opportunity to Resolve Collective Deficiency in Local Capacity Area Resources.

Where the ISO determines that a need for Eligible Capacity exists under Section 43.2.1.4, but prior to any designation of Eligible Capacity, the ISO shall issue a market notice, no later than fifteen (15) days after the Scheduling Coordinator for an LSE is required to submit its annual Resource Adequacy Plans, identifying the deficient Local Capacity Area, the quantity of capacity that would permit the deficient Local Capacity Area to comply with the Local Capacity Technical Study criteria provided in Section 40.3.1.1 of Appendix CC and, where only specific resources are effective to resolve the Reliability Criteria deficiency, the ISO shall provide the identity of such resources. Any Scheduling Coordinator for an LSE may submit a revised annual Resource Adequacy Plan within thirty (30) days after the ISO issues the market notice herein, demonstrating procurement of additional Local Capacity Area Resources consistent with the market notice issued under this Section.

Any Scheduling Coordinator for an LSE that provides such additional Local Capacity Area Resources consistent with the market notice under this Section shall have its share of any TCPM procurement costs under Section 43.8 reduced on a proportionate basis. If the full quantity of capacity is not reported to the ISO under revised annual Resource Adequacy Plans in accordance with this Section, the ISO may designate Eligible Capacity sufficient to alleviate the deficiency.

43.2.2 Selection of Eligible Capacity Designated for Local Reliability

The ISO will make designations of Eligible Capacity under Section 43.2 based on the lowest overall cost for each Local Capacity Area considering the following factors: the effectiveness of the Eligible Capacity, the quantity of Eligible Capacity of the resource relative to the remaining amount of capacity that is needed; and the Start-Up and Minimum Load Costs associated with the Eligible Capacity. The ISO shall have reasonable allowance to designate under the TCPM an amount of Eligible Capacity from a Generating Unit that is slightly more or slightly less than a deficiency due to the quantity of Eligible Capacity from such Generating Unit that is available and suitable to meet the deficiency, consistent with the criteria in this section.

43.3 System TCPM Designations

The ISO may designate Eligible Capacity to the extent provided in this Section 43.3.

43.3.1 Annual System TCPM Designations

Following the ISO's review under Section 40.7 of Appendix CC of the annual Resource Adequacy Plans submitted pursuant to Section 40.2.1 of the ISO Tariff and Sections 40.2.1.1, 40.2.2.4, 40.2.3.4 or 40.2.4 of Appendix CC, and its review of any designation of Eligible Capacity pursuant to Section 43.2.1.3, the ISO may designate Eligible Capacity or System Resources to provide services under the TCPM under this Section 43.3 to the extent necessary to cover the aggregate Year-Ahead System Resource Deficiency consistent with the criteria set forth in Section 43.3.3.

A designation of Eligible Capacity or System Resources to provide services under the TCPM made pursuant to this Section 43.3.1 shall be for a minimum term of three months, provided that, at the discretion of the ISO, the designation term may be extended up to a maximum term of the five summer months of May through September, *provided that the term of the designation may not extend into a subsequent Resource Adequacy Compliance Year,* and provided further, that in no event shall the term of any TCPM designation under this section extend beyond midnight on the day before the MRTU Tariff goes into effect.

43.3.2 Monthly System TCPM Designations

Following its review under Section 40.7 of Appendix CC of the monthly Resource Adequacy Plans submitted by Scheduling Coordinators pursuant to Section 40.2.2, the ISO may designate Eligible Capacity or System Resources to provide services under the TCPM under this Section 43.3 to the extent necessary to cover the aggregate Month-Ahead System Resource Deficiency consistent with the criteria set forth in Section 43.3.3.

Designations of Eligible Capacity or System Resources to provide services under the TCPM made pursuant to this Section 43.3.2 shall be for the lesser of three months or the remainder of the calendar year, *provided that the term of the designation may not extend into a subsequent Resource Adequacy Compliance Year, and provided further, that in no event shall the term of any TCPM designation under this section extend beyond midnight on the day before the MRTU Tariff goes into effect.*

43.3.3 Selection of Eligible Capacity Designated for System Reliability

The ISO will make designations of Eligible Capacity or System Resources under this Section 43.3 based on the following factors: the effectiveness of the Eligible Capacity in addressing local and/or zonal constraints in addition to meeting system needs; the quantity of Eligible Capacity of the resource; the Start-Up and Minimum Load Costs associated with the Eligible Capacity; and the effectiveness of the Eligible Capacity at reducing the Minimum Load Costs that might otherwise be incurred as a result of must-offer waiver denials. System Resources shall be subject to the ISO's established import limits as specified in accordance with Section 40.5.2.2. The ISO shall have reasonable allowance to designate under the **TCPM** an amount of Eligible Capacity from a Generating Unit or System Resource that is slightly more or slightly less than a deficiency due to the quantity of Eligible Capacity from such Generating Unit or System Resource that is available and suitable to meet the deficiency, consistent with the criteria in this section.

43.4 Designations For **TCPM Significant Events**

The ISO may designate Eligible Capacity or System Resources to provide service **on a prospective basis** under this Section 43.4 following a **TCPM** Significant Event, **to the extent necessary to maintain compliance with Reliability Criteria** and taking into account the expected duration of the **TCPM** Significant Event. **Capacity designated under Section 43.4 shall have an initial term of thirty (30) days. If the ISO determines that the TCPM Significant Event is likely to extend beyond the thirty (30) day period, the ISO shall extend the designation for another sixty (60) days. During this additional sixty (60) day period, the ISO will provide Market Participants with an opportunity to provide alternative solutions to meet the ISO's operational and reliability needs in response to the TCPM Significant Event, rather than rely on the ISO's designation of capacity under the TCPM. The ISO shall consider and implement, if acceptable to the ISO in accordance with Good Utility Practice, such alternative solutions provided by Market Participants in a timely manner. If Market Participants do not submit any alternatives to the designation of TCPM capacity**

that are fully effective in addressing the deficiencies in Reliability Criteria resulting from TCPM Significant Event, the ISO shall extend the term of the designation under Section 43.4 for the expected duration of the TCPM Significant Event. If there is a reasonable alternative solution that fully resolves the ISO's operational and reliability needs, the ISO will not extend the designation under Section 43.4. The term of the designation may not extend into a subsequent Resource Adequacy Compliance Year. Moreover, in no event shall the term of such TCPM designation extend beyond midnight on the day before the MRTU Tariff goes into effect. Any TCPM designations under this section shall be in accordance with the criteria set forth in Section 43.4.1.

43.4.1 Selection of Eligible Capacity for TCPM Significant Events

The ISO will make designations of Eligible Capacity under Section 43.4 based on the lowest overall cost for each TCPM Significant Event considering the following factors: the effectiveness of the Eligible Capacity, the quantity of Eligible Capacity of the resource relative to the remaining amount of capacity that is needed; and the Start-Up and Minimum Load Costs associated with the Eligible Capacity.

The ISO shall have reasonable allowance to designate under the TCPM an amount of Eligible Capacity from a Generating Unit that is slightly more or slightly less than the capacity necessary to remedy a TCPM Significant Event due to the quantity of Eligible Capacity of such Generating Unit that is available and suitable to meet the TCPM Significant Event, consistent with the criteria in this section.

43.5 Obligations of a Resource Designated under the **TCPM**

43.5.1 Must-Offer Obligations

Generating Units designated under the **TCPM** shall be subject to all of the availability, must-offer, dispatch, testing, reporting, and verification obligations applicable to Resource Adequacy Resources identified in Resource Adequacy Plans under Section 40.6A of the ISO Tariff. Generating Units designated under the **TCPM** must offer available capacity into the Ancillary Services markets to the extent capable.

43.5.2 Replacement Option

If a Generating Unit designated under the **TCPM** is unavailable when issued a must-offer waiver denial by the ISO pursuant to Section 40.7.6 of the ISO Tariff, the Scheduling Coordinator for the resource may, within 2 hours for a must-offer waiver denial issued prior to the Hour-Ahead market and within 30 minutes for a must-offer waiver denial issued in Real-Time, substitute capacity from such Generating Unit with Eligible Capacity that: (i) is located at the same bus, or (ii) if not located at the same bus, is located in the same Local Capacity Area, and which meets the ISO's effectiveness and operational needs, including size of resource, as determined by the ISO in its reasonable discretion. If the Scheduling Coordinator substitutes such Eligible Capacity, the Scheduling Coordinator must pay all additional Minimum Load Costs, Start-Up Costs, Emissions Costs (above the corresponding costs of the Generating Unit that is being substituted), and any bilateral contract costs incurred by the Scheduling Coordinator, as a result of the substitution. The actual Availability of the substitute resource will be used for the purposes of the calculations in Appendix F, Schedule 6.

43.5.3 Termination of Obligations

If a Participating Generator's Eligible Capacity is designated by the CAISO under the terms of the **TCPM**, and the Participating Generator has not filed a notice to withdraw from the Participating Generator Agreement ("PGA"), then the Participating Generator shall be obligated to perform in

accordance with the **TCPM** for the term of the **TCPM** designation. If a Participating Generator's Eligible Capacity is designated under the terms of the **TCPM** after the Participating Generator has filed a notice to withdraw from its PGA, then the Participating Generator shall be obligated to perform in accordance with the **TCPM** until the date that its PGA effectively terminates, but the Participating Generator shall be under no obligation to so perform after the effective date of the PGA termination. If a Participating Generator's Eligible Capacity is designated under the **TCPM** after the Participating Generator has filed notice to withdraw from its PGA, and the Participating Generator agrees to provide service under the **TCPM**, then the Participating Generator will enter into a PGA for the designated generating unit and invoice the ISO for any actual applicable restoration costs as provided in the RMR Service Agreement.

43.6 **TCPM Report**

43.6.1 **TCPM Designation Market Notice**

*The ISO shall issue a market notice within two (2) Business Days of a **TCPM** designation. The market notice shall include a preliminary description of what caused the **TCPM** Significant Event, the name of the resource(s) procured, the preliminary expected duration of the **TCPM** Significant Event, the initial designation period, and an indication that a designation report is being prepared.*

43.6.2 Designation of a Resource under the **TCPM Tariff**

*The ISO shall post a designation report to the ISO Website and provide a market notice of the availability of the report within the earlier of thirty (30) days of procuring a resource under the **TCPM** or ten (10) days after the end of the month. The designation report shall include the following information:*

- (1) A description of the reason for the designation (LSE procurement shortfall, Local Capacity Area Resource effectiveness deficiency, or **TCPM** Significant Event), and an explanation of why it was necessary for the ISO to utilize the **TCPM** authority);*

(2) *The following information would be reported for all backstop designations:*

(a) *the resource name;*

(b) *the amount of TCPM Capacity designated (MW),*

(c) *an explanation of why that amount of TCPM Capacity was designated,*

(d) *the date TCPM Capacity was designated,*

(e) *the duration of the designation; and*

(f) *the price for the TCPM procurement; and*

(3) *If the reason for the designation is a TCPM Significant Event, the ISO will also include:*

(a) *a discussion of the event or events that have occurred, why the ISO has procured TCPM Capacity, and how much has been procured;*

(b) *an assessment of the expected duration of the TCPM Significant Event;*

(c) *the duration of the initial designation (thirty (30) days); and*

(d) *a statement as to whether the initial designation has been extended (such that the backstop procurement is now for more than thirty (30) days), and, if it has been extended, the length of the extension.*

43.7 Payments to Resources Designated Under the TCPM

43.7.1 TCPM Capacity Payment

Scheduling Coordinators representing resources designated under this Section 43 will receive a TCPM Capacity Payment equal to the product of the Net Qualifying Capacity, the relevant Availability Factor as determined in accordance with Appendix F, Schedule 6, and the difference between the monthly TCPM charge and 95% of the Peak Energy Rent, *i.e.*, Net Qualifying Capacity x Availability Factor x (Monthly TCPM Charge (Monthly Peak Energy Rent x .95)). The ISO shall determine the Availability Factor, Monthly TCPM Charge and Monthly Peak Energy Rent in accordance with Appendix F, Schedule 6 of the Tariff. For purposes of this section 43.7.1, the term Net Qualifying Capacity shall mean the Megawatt

value for a **TCPM** resource as reflected in the document entitled Qualifying Capacity Megawatt Values for RA Planning Purposes (or any successor document) as posted on the ISO website, provided that, to the extent a particular resource has a stated monthly value(s), the applicable Net Qualifying Capacity shall be the average of the stated values for the months in which the resource will have an **TCPM** designation.

For purposes of the **TCPM designation, except for TCPM Significant Events**, availability shall be calculated as the ratio of: (1) the sum of the Net Qualifying Capacity MW for each hour of the month across all hours of the month, where the actual capacity MW available to the ISO shall be substituted for Net Qualifying Capacity MW for each hour the resource is not on an Authorized Outage, to (2) the product of Net Qualifying Capacity MW and the total hours in the month. **For purposes of TCPM designations for**

TCPM Significant Events, the Availability Factor shall be calculated as the ratio of: (1) the sum of the TCPM Capacity MW for each hour across all hours of the month or part of the month for which a unit is designated, whichever is applicable, where the actual capacity MW available to the ISO, if less than the TCPM Capacity MW, shall be substituted for TCPM Capacity MW for each hour the resource is not available and is not on an authorized Outage, to (2) the product of TCPM Capacity MW and the total hours in the in the month or part of the month for which a unit is designated, whichever is applicable.

For purposes of this section, an Authorized Outage shall be limited to the following: (a) an ISO-approved, planned outage that exists at the time of **TCPM** designation and is scheduled to occur during the term of an **TCPM** designation provided that (i) such outage is not the result of a prior outage that was forced or not otherwise scheduled and approved by the ISO, and (ii) such outage may be rescheduled by the ISO during the term of the **TCPM** designation period, provided that the term of the ISO-approved outage and the capacity derate at time of the **TCPM** designation are not exceeded, or (b) an ISO-approved maintenance outage that is scheduled during the **TCPM** designation period, provided such outage is not the result of a prior outage that was forced or not otherwise scheduled and approved by the ISO.

43.7.2 Minimum Load, Emissions and Start-Up Costs

43.7.2.1 Minimum Load Costs

Scheduling Coordinators representing resources designated under this Section 43 shall be eligible for recovery of Minimum Load Costs in the same manner that Scheduling Coordinators representing Resource Adequacy Resources included in Resource Adequacy Plans are eligible for the recovery of such costs under Sections 40.6B of the Tariff.

43.7.2.1.1 Allocation of Unrecovered Minimum Load Costs

Unrecovered Minimum Load Costs under Section 43.7.2.1 shall be allocated in accordance with Section 40.6B.5 of the ISO Tariff.

43.7.2.2 Emissions Costs

Scheduling Coordinators representing resources designated under this Section 43 shall be eligible for recovery of Emissions Costs in the same manner that Scheduling Coordinators representing Resource Adequacy Resources included in Resource Adequacy Plans are eligible for the recovery of such costs under Sections 40.11 of the ISO Tariff.

43.7.2.2.1 Recovery of Emissions Costs

The ISO will recover funds to pay Emissions Costs under Section 43.7.2.2 in accordance with Sections 40.11 of the ISO Tariff.

43.7.2.3 Start-Up Costs

Scheduling Coordinators representing resources designated under this Section 43 shall be eligible for recovery of Start-Up Costs in the same manner that Scheduling Coordinators representing Resource Adequacy Resources included in Resource Adequacy Plans are eligible for the recovery of such costs under Sections 40.12 of the ISO Tariff.

43.7.2.3.1 Recovery of Start-Up Costs

The ISO will recover funds to pay Start-Up Costs under Section 43.7.2.3 in accordance with Sections 40.12 of the ISO Tariff.

43.8 Allocation of **TCPM Capacity Payment Costs**

For each month, the ISO shall allocate the costs of **TCPM** Capacity Payments made pursuant to Section 43.7.1 as follows:

- (1) Annual System **TCPM** Designations: If the ISO makes **TCPM** designations under Section 43.3.1, then the ISO will allocate the total costs of **TCPM** Capacity Payments for such **TCPM** designations (for the full term of those **TCPM** designations) pro rata to each **deficient** SC-RA Entity based on its portion of the aggregate Year-Ahead System **Resource** Deficiency.
- (2) Monthly System **TCPM** Designations: If the ISO makes **TCPM** designations under Section 43.3.2, then the ISO will allocate the total costs of **TCPM** Capacity Payments for such

TCPM designations (for the full term of those **TCPM** designations) pro rata to each **deficient** SC-RA Entity based on its portion of the aggregate Month-Ahead System **Resource** Deficiency.

- (3) **Local TCPM Designations.** If the ISO makes local **TCPM** designations, then the ISO will allocate the total costs of **TCPM** Capacity Payments for such **TCPM** designations (for the full term of those **TCPM** designations) pro rata to each Scheduling Coordinator for a **deficient** RA Entity based on the ratio of its Local Resource Adequacy Requirement Deficiency to the **sum of the Local Resource Adequacy Requirement Deficiencies within a TAC Area.** To the extent there is a Local Resource Adequacy Requirement Deficiency in two or more **Local Capacity** Areas that can be satisfied by designating a single unit under the **TCPM**, the ISO shall allocate the total costs of **TCPM** Capacity Payments for such **TCPM** designation (for the full term of the designation) pro rata to each Scheduling Coordinator for an RA Entity that has a Local Resource Adequacy Requirement Deficiency in such **Local Capacity** Areas based on the ratio of its Local Resource Adequacy Requirement Deficiency to the aggregate Local Resource Adequacy Requirement Deficiency in those **Local Capacity** Areas.

- (4) **Collective Local Capacity Shortfalls.** *If the ISO makes designations under Section 43.2.1.4 the ISO shall allocate the costs of such designations to all Scheduling Coordinators for LSEs in the TAC Area(s) in which the deficient Local Capacity Area was located. The allocation will be based on such Scheduling Coordinators' proportionate share of Load in such TAC Area(s) as determined in accordance with Section 40.3.2 of Appendix CC, excluding Scheduling Coordinators for LSEs that procured additional capacity in accordance with Section 43.2.1.4.1 on a proportionate basis, to the extent of their additional procurement.*

- (5) **TCPM Significant Event Designations.** *If the ISO makes any TCPM Significant Event designations under Section 43.4, the ISO shall allocate the costs of such designations to all Scheduling Coordinators for LSEs that serve Load in the TAC Area(s) in which the TCPM Significant Event caused or threatened to cause a failure to meet Reliability Criteria based on the percentage of actual MWh Load of each LSE represented by the Scheduling Coordinator in the TAC Area(s) to total MWh Load in the TAC Area(s) as recorded in the ISO Settlement system for the actual days during any Settlement month period over which the designation has occurred.*

43.9 Crediting of TCPM Capacity

The ISO shall credit TCPM designations to the resource adequacy obligations of Scheduling Coordinators for Load Serving Entities as follows:

- (a) *To the extent the cost of TCPM designation under Section 43.2.1.3 is allocated to a Scheduling Coordinator on behalf of a LSE under Section 43.8.(3), the ISO shall provide the Scheduling Coordinator on behalf of the LSE, for the term of the designation, credit towards (1) the LSE's Local Capacity Area Resource obligation under Section 43.2.1.3 in an amount equal to the LSE's pro rata share of the TCPM Capacity designated under Section 43.2.1.3 and (2) the LSE's Demand and Reserve Margin requirements determined under Section 40 in an amount equal to the LSE's pro rata share of the TCPM Capacity designated under Section 43.2.1.3.*
- (b) *To the extent the cost of ISO designation under Section 43.2.1.4 is allocated to a Scheduling Coordinator on behalf of a LSE under Section 43.8 (4), the ISO shall provide the Scheduling Coordinator on behalf of the LSE, for the term of the designation, credit towards the LSE's Demand and Reserve Margin requirements determined under Section 40 in an amount equal to the LSE's pro rata share of the TCPM Capacity designated under Section 43.2.1.4.*

- (c) *To the extent the cost of TCPM designation under Section 43.3.1 is allocated to a Scheduling Coordinator on behalf of a LSE under Section 43.8.(1), and the designation is for greater than one month under Section 43.3.1, the ISO shall provide the Scheduling Coordinator on behalf of the LSE, for the term of the designation, credit towards the LSE's Demand and Reserve Margin requirements determined under Section 40 in an amount equal to the LSE's pro rata share of the TCPM Capacity designated under Section 43.3.1.*
- (d) *The credit provided in this Section shall be used for determining the need for the additional designation of TCPM Capacity under Section 43.1 and for allocation of TCPM costs under Section 43.8.*
- (e) *For each Scheduling Coordinator that is provided credit pursuant to this Section, the ISO shall provide information, including the quantity of capacity procured in MW, necessary to allow the CPUC, other Local Regulatory Authority, or federal agency with jurisdiction over the LSE on whose behalf the credit was provided to determine whether the LSE should receive credit toward its resource adequacy requirements adopted by such agencies or authorities.*

ISO TARIFF APPENDIX A
Master Definitions Supplement

Appendix A **Master Definition Supplement**

Access Charge

A charge paid by all UDCs and MSS Operators with Gross Load in a PTO Service Territory, as set forth in Section 2.6.1. The Access Charge includes the High Voltage Access Charge, the Transition Charge and the Low Voltage Access Charge. The Access Charge will recover the Participating TO's Transmission Revenue Requirement in accordance with Appendix F, Schedule 3.

Active Zone

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

Adjustment Bid

A bid in the form of a curve defined by (i) the minimum MW output to which a Scheduling Coordinator will permit a resource (Generating Unit or Dispatchable Load) included in its Schedule or, in the case of an inter-Scheduling Coordinator trade, included in its Schedule or the Schedule of another Scheduling Coordinator, to be redispatched by the ISO; (ii) the maximum MW output to which a Scheduling Coordinator will permit the resource included in its Schedule or, in the case of an inter-Scheduling Coordinator trade, included in its Schedule or the Schedule of another Scheduling Coordinator, to be redispatched by the ISO; (iii) up to a specified number of MW values in between; (iv) a preferred MW operating point; and (v) for the ranges between each of the MW values greater than the preferred operating point, corresponding prices (in \$/MWh) for which the Scheduling Coordinator is willing to increase the output of the resource and sell Energy from that resource to the ISO (or, in the case of a Dispatchable Load, decrease the Demand); and (vi) for the ranges between each of the MW values less than the preferred operating point, corresponding prices (in \$/MWh) for which the Scheduling Coordinator is willing to decrease the output of the resource and purchase Energy from the ISO at the resource's location (or, in the case of a Dispatchable Load, increase the Demand). This data for an Adjustment Bid must result in a monotonically increasing curve.

Administrative Price

The price set by the ISO in place of a Market Clearing Price when, by reason of a System Emergency, the ISO determines that it no longer has the ability to maintain reliable operation of the ISO Controlled Grid relying solely on the economic Dispatch of Generation. This price will remain in effect until the ISO considers that the System Emergency has been contained and corrected.

Adverse System Impact

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

Affected System

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

Affected System Operator

The entity that operates an Affected System.

Affiliate

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.

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 Import Capability

The Maximum Import Capability of a branch group into the ISO Control Area in MW deliverable to the ISO Control Area based on ISO study criteria minus the sum in MW of all Existing Contracts and Transmission Ownership Rights over that branch group held by load serving entities that do not serve Load within the ISO Control Area.

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.

	rating guidelines, less any reserved uses applicable to the path. The ISO Control Center located in Alhambra, California.
<u>Backup ISO Control Center</u>	
<u>Balanced Schedule</u>	A Schedule shall be deemed balanced when Generation, adjusted for Transmission Losses equals Demand with respect to all entities for which a Scheduling Coordinator schedules.
<u>Balancing Account</u>	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.
<u>Black Start</u>	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.
<u>Black Start Generator</u>	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.
<u>Bulk Supply Point</u>	A UDC metering point.
<u>Business Day</u>	Monday through Friday, excluding federal holidays and the day after Thanksgiving Day.
<u>Business Practice Manual (BPM)</u>	A collection of documents made available by the CAISO on the CAISO Website that contain the rules, policies, procedures and guidelines established by the CAISO for operational, planning, accounting and settlement requirements of CAISO Market activities, consistent with the CAISO Tariff.
<u>C.F.R.</u>	Code of Federal Regulations.
<u>CAISO</u>	The California Independent System Operator Corporation, a California non-profit public benefit corporation that operates the transmission facilities of all Participating TOs and dispatches certain Generating Units and Loads.
<u>CAISO Controlled Grid</u>	The system of transmission lines and associated facilities of the Participating TOs that have been placed under the CAISO's Operational Control.
<u>CAISO Demand</u>	Power delivered to Load internal to the ISO Control Area.

<u>CAISO Tariff</u>	The California Independent System Operator Corporation Operating Agreement and Tariff, dated March 31, 1997, as it may be modified from time to time.
<u>CAISO Website</u>	The CAISO internet home page at http://www.aiso.com / or such other internet address as the CAISO shall publish from time to time.
<u>Calendar Day</u>	Any day including Saturday, Sunday or a federal holiday.
<u>Candidate CRR Holder</u>	Defined in Appendix BB.
<u>CDWR-SWP</u>	The California Department of Water Resources, State Water Project.
<u>CDWR-SWP Participating Generating Units</u>	The Generating Units operated by the California Department of Water Resources, State Water Project, that are subject to a Participating Generator Agreement with the ISO.
<u>Certificate of Compliance</u>	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.
<u>Check Meter</u>	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 Revenue

Defined in Appendix BB.

Right (CRR)

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

Generating resources with only two viable operating states: (a) off-line or (b) operating at their maximum output level.

Generation

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

<u>Control Area Operator</u>	The person responsible for managing the real-time operations of a Control Area.
<u>Converted Rights</u>	Those transmission service rights as defined in Section 16.21A.1 of the ISO Tariff.
<u>Core Reliability Services - Demand Charge</u>	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.
<u>Core Reliability Services – Energy Export Charge</u>	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.
<u>CPUC</u>	The California Public Utilities Commission, or its successor.
<u>Credit Margin</u>	The quantity equal to Expected Congestion Revenue minus Fifth Percentile Congestion Revenue.
<u>Credit Rating Default Probability</u>	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.
<u>CRR Auction Price</u>	The positive or negative price to pay or be paid for a CRR at auction.
<u>CRR Holder</u>	As defined in Appendix BB.
<u>Critical Protective System</u>	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.
<u>CTC (Competition Transition Charge)</u>	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.

Decline Monthly Charge – Exports

A charge that applies to the aggregate of a Scheduling Coordinator's Hourly Pre-Dispatch Supplemental Energy bids to export Energy that are not delivered in a trading month, as determined pursuant to Section 11.31.1.

Decline Monthly Charge – Imports

A charge that applies to the aggregate of a Scheduling Coordinator's Hourly Pre-Dispatch Supplemental Energy bids to import Energy that are not delivered in a trading month, as determined pursuant to Section 11.31.1.

Decline Potential Charge – Exports

A potential charge that is calculated for any portion of an Hourly Pre-Dispatch Supplemental Energy bid to export Energy that is not delivered for any reason, which potential charge and its applicability are determined pursuant to Section 11.31.

Decline Potential Charge – Imports

A potential charge that is calculated for any portion of an Hourly Pre-Dispatch Supplemental Energy bid to import Energy that is not delivered for any reason, which potential charge and its applicability are determined pursuant to Section 11.31.

Decline Threshold Percentage – Imports/Exports

The rate at which Scheduling Coordinators may fail to deliver imports or exports in accordance with Hourly Pre-Dispatch bids for Supplemental Energy without incurring Decline Monthly Charges – Imports or Decline Monthly Charges – Exports, as measured by the respective percentages of Hourly Pre-Dispatch Supplemental Energy bids for import or export MWh quantities that the Scheduling Coordinator does not deliver during a trading month. The Decline Threshold Percentage – Imports/Exports is ten percent (10%).

**Decline Threshold
Quantity –
Imports/Exports**

The MWh quantity of Hourly Pre-Dispatch Supplemental Energy bids for imports or exports of Energy that a Scheduling Coordinator may fail to deliver during a trading month without incurring Decline Monthly Charges – Imports or Decline Monthly Charges – Exports. The Decline Threshold Quantity – Imports/Exports is 300 MWh.

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 Generating Facility could provide Energy to the ISO Controlled Grid at peak load, under a variety of severely stressed conditions, such that the aggregate of Generation in the local area can be delivered to the aggregate of Load on the ISO Controlled Grid, consistent with the ISO's reliability criteria and procedures.

**Delivery Network
Upgrades**

Transmission facilities at or beyond the Point of Interconnection, other than Reliability Network Upgrades, identified in the Interconnection Studies to relieve constraints on the ISO Controlled Grid.

Delivery Point

The point where a transaction between Scheduling Coordinators is deemed to take place. It can be either the Generation input point, a Demand Take-Out Point, or a transmission bus at some intermediate location.

Demand

The rate at which Energy is delivered to Loads and Scheduling Points by Generation, transmission or distribution facilities. It is the product of voltage and the in-phase component of alternating current measured in units of watts or standard multiples thereof, e.g., 1,000W=1kW, 1,000kW=1MW, etc.

Demand Forecast

An estimate of Demand over a designated period of time.

<u>Department of Market Analysis (DMA)</u>	The unit established under Appendix P.1.
<u>Direct Access Demand</u>	The Demand of Direct Access End-Users.
<u>Direct Access End-User</u>	An Eligible Customer located within the Service Area of a UDC who purchases Energy and Ancillary Services through a Scheduling Coordinator.
<u>Dispatch</u>	The operating control of an integrated electric system to: i) assign specific Generating Units and other sources of supply to effect the supply to meet the relevant area Demand taken as Load rises or falls; ii) control operations and maintenance of high voltage lines, substations, and equipment, including administration of safety procedures; iii) operate interconnections; iv) manage Energy transactions with other interconnected Control Areas; and v) curtail Demand.
<u>Dispatch Instruction</u>	An instruction by the ISO to a resource for increasing or decreasing its energy supply or demand from the Hour-Ahead Schedule to a specified operating point pertaining to real-time operations.
<u>Dispatch Interval</u>	The time period, which may range between five (5) and thirty (30) minutes, over which the ISO's RTD Software measures deviations in Generation and Demand, and selects Ancillary Service and Supplemental Energy resources to provide balancing Energy in response to such deviations. The Dispatch Interval shall be five (5) minutes. Following a decision by the ISO Governing Board, the ISO may, by seven (7) days' notice published on the ISO's Home Page, at http://www.caiso.com (or such other internet address as the ISO may publish from time to time), increase or decrease the Dispatch Interval within the range of five (5) to thirty (30) minutes.
<u>Dispatch Interval Ex Post Prices</u>	The price of Imbalance Energy determined each Dispatch Interval based on 1) the Imbalance Energy requirements in that Dispatch Interval, and 2) the Energy Bid price of the resource eligible to set the price. The Dispatch Interval Ex Post Price is used to determine

	other prices used to settle Imbalance Energy.
<u>Dispatch Operating Point</u>	The expected operating point of a resource that has received a Dispatch Instruction. The resource is expected to operate at the Dispatch Operating Point after completing the Dispatch Instruction, taking into account any relevant ramp rate and time delays. Energy expected to be produced or consumed above or below the Final Hour-Ahead Schedule in response to a Dispatch Instruction constitutes Instructed Imbalance Energy. For resources that have not received a Dispatch Instruction, the Dispatch Operating Point defaults to the corresponding Final Hour-Ahead Schedule.
<u>Dispatchable Load</u>	Load which is the subject of an Adjustment Bid.
<u>Distribution System</u>	The distribution assets of an IOU or Local Publicly Owned Electric Utility.
<u>Distribution Upgrades</u>	The additions, modifications, and upgrades to the Participating TO's electric systems that are not part of the ISO Controlled Grid. Distribution Upgrades do not include Interconnection Facilities.
<u>Dynamic Schedule</u>	A telemetered reading or value which is updated in real time and which is used as a schedule in the ISO EMS calculation of ACE and the integrated value of which is treated as a schedule for interchange accounting purposes.
<u>EEP (Electrical Emergency Plan)</u>	A plan to be developed by the ISO in consultation with UDCs to address situations when Energy reserve margins are forecast to be below established levels.
<u>Electronic Data Interchange (EDI)</u>	The routine exchange of business documented on electronic media such as purchase orders, invoices and remittance. The format of the data is based on an industry-approved format such as those published by the ANSI ASC X12 committee.
<u>Eligible Capacity</u>	Capacity of Generating Units of Participating Generators located within the ISO Control Area except the following: capacity associated with hydroelectric generation, nuclear generation, QFs, generation resources within a Metered Subsystem, resources owned by the California Department of Water Resources, State

Water Project; capacity of a Generating Unit with a Reliability Must-Run contract, during the term of such contract; capacity of a Resource Adequacy Resource that is identified in any Resource Adequacy Plan in accordance with Section 40, during the time that such capacity is identified on the Resource Adequacy Plan; and capacity that has been designated to provide service under the **TCPM**, during the term of the designation.

Eligible Customer

(i) any utility (including Participating TOs, Market Participants and any power marketer), Federal power marketing agency, or any person generating Energy for sale or resale; Energy sold or produced by such entity may be Energy produced in the United

	<p>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.</p>
<u>Eligible Intermittent Resource</u>	<p>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.</p>
<u>Emissions Cost Charge</u>	<p>The charge determined in accordance with Section 40.11.</p>
<u>Emissions Cost Demand</u>	<p>The level of Demand specified in Section 40.11.3.</p>
<u>Emissions Cost Invoice</u>	<p>The invoice submitted to the ISO in accordance with Section 40.11.6.</p>
<u>Emissions Cost Trust Account</u>	<p>The trust account established in accordance with Section 40.11.2.</p>
<u>Emissions Costs</u>	<p>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.</p>
<u>EMS (Energy Management System)</u>	<p>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.</p>
<u>Encumbrance</u>	<p>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.</p>
<u>End-Use Customer or</u>	<p>A consumer of electric power who consumes such power to satisfy a</p>

<u>End-User</u>	Load directly connected to the ISO Controlled Grid or to a Distribution System and who does not resell the power.
<u>End-Use Meter Data</u>	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.
<u>End-Use Meter</u>	A metering device collecting Meter Data with respect to the Energy consumption of an End-User.
<u>Energy</u>	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.
<u>Energy Bid</u>	The price at or above which a Generator has agreed to produce the next increment of Energy.
<u>Energy Resource Area (ERA)</u>	A geographic region certified by the California Public Utilities Commission and the California Energy Commission as an area in which multiple LCRIGs could be located, provided that, for the interim period before those agencies certify such areas and for LCRIFs that are proposed to connect LCRIGs located outside the State of California, an Energy Resource Area shall mean a geographic region that would be connected to the CAISO Controlled Grid by an LCRIF with respect to which the CAISO Governing Board determines that all of the requirements of Section 24.1.3 are satisfied, except for the requirement that the LCRIGs to which the LCRIF would connect are located in an area certified as an ERA by those agencies.
<u>Energy Transmission Services Net Energy Charge</u>	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.

Exempt Scheduling Deviation

The difference between a Day-Ahead Schedule submitted by any Scheduling Coordinator, pursuant to Section 4.5.4.2.1.1, and its Demand Forecast, pursuant to Section 31.1.4.1, within any UDC or MSS Service Area that does not exceed the lesser of (a) three (3) MW or (b) five percent (5%) of that Scheduling Coordinator's Demand Forecast for the relevant UDC or MSS Service Area.

Export Percentage

Export Percentage will be calculated for each Participating Intermittent Resource as the ratio of the Participating Intermittent Resource's Pmax in the ISO Master File minus the MW subject to an exemption under EIRP 5.3.2 on a MW basis to the Participating Intermittent Resource's Pmax in the ISO Master File.

Exporting Participating Intermittent Resource

A Participating Intermittent Resource with Export Percentage greater than zero (0).

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

Transmission Loss that is calculated based on Ex Post GMM.

Loss

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.

<u>Existing Contract Import Capability</u>	The quantity of Available Import Capability reserved for Existing Contracts and Transmission Ownership Rights held by Load Serving Entities that serve Load within the ISO Control Area under Step 3 of ISO Tariff Section 40.5.2.2.1.
<u>Existing High Voltage Facility</u>	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.
<u>Existing Rights</u>	Those transmission service rights defined in Section 16.2.1.1 of the ISO Tariff.
<u>Expected Congestion Revenue</u>	The mean value based on the probability distribution of the historic Congestion revenue of a CRR.
<u>Facility Owner</u>	An entity owning transmission, Generation, or distribution facilities connected to the ISO Controlled Grid.
<u>Facility Study</u>	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.

<u>Facility Study Agreement</u>	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.
<u>Fed-Wire</u>	The Federal Reserve Transfer System for electronic funds transfer.
<u>FERC</u>	The Federal Energy Regulatory Commission or its successor.
<u>FERC Annual Charges</u>	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.
<u>FERC Annual Charge Recovery Rate</u>	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.
<u>FERC Annual Charge Trust Account</u>	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.
<u>FERC Must-Offer Generator</u>	All entities defined by Section 40.7.1 of this ISO Tariff.
<u>Fifth Percentile</u>	The fifth percentile value based on the probability distribution of the historic Congestion revenue of a CRR.
<u>Congestion Revenue</u>	A statement of consent by the ISO Control Center to initiate a scheduled Outage.
<u>Final Approval</u>	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.
<u>Final Day-Ahead Schedule</u>	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.
<u>Final Hour-Ahead Schedule</u>	The invoice due from a RMR Owner to the ISO at termination of the RMR Contract.
<u>Final Invoice</u>	

Final Schedule

A Schedule developed by the ISO following receipt of a Revised Schedule from a Scheduling Coordinator.

Final NERC/WECC

Charge

A final invoice issued by the ISO that reflects an allocation of NERC/WECC Charges to a Scheduling Coordinator based on the Final NERC/WECC Charge Rate for the NERC/WECC Charge Assessment Year.

Final NERC/WECC Charge

Rate

The rate to be paid by Scheduling Coordinators for NERC/WECC Charges based on the WECC invoice to the ISO for NERC/WECC Charges for a given year and on the NERC/WECC Metered Demand for the NERC/WECC Charge Assessment Year.

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

<u>Region</u>	operate in a stable manner and must ramp through at maximum ramp capacity.
<u>Forced Outage</u>	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.
<u>Forecast Fee</u>	The charge imposed on a Participating Intermittent Resource pursuant to the terms of Appendix Q and ISO Tariff Appendix F, Schedule 4.
<u>Forward Scheduling Charge</u>	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.
<u>FPA</u>	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.
<u>FTR (Firm Transmission Right)</u>	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.
<u>FTR Bidder</u>	An entity that submits a bid in an FTR auction conducted by the ISO in accordance with Section 36.4 of the ISO Tariff.
<u>FTR Holder</u>	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 limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

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 customer's 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 CAISO 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, provided that the High Voltage Transmission Facilities of a Participating TO shall include any Location Constrained Resource Interconnection Facility of that Participating TO that has been turned over to the CAISO's Operational Control.

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.

Historical Expected Value

The expected value of a CRR, as calculated by the ISO, based on monthly historical market operation data for the applicable month. Such values will be established based on at least one (1) year and up to three (3) years of historical market operations data.

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.

Hour-Ahead Forecast

The Energy forecast to be used by the Scheduling Coordinator representing a Participating Intermittent Resource for its Preferred Hour-Ahead Schedule, in accordance with Appendix Q.

Hour-Ahead Market

The forward market for Energy and Ancillary Services to be supplied during a particular Settlement Period that is conducted by the ISO and other Scheduling Coordinators which opens after the ISO's acceptance of the Final Day-Ahead Schedule for the Trading Day in which the Settlement Period falls and closes with the ISO's acceptance of the Final Hour-Ahead Schedule.

Hour-Ahead Schedule

A Schedule prepared by a Scheduling Coordinator or the ISO before the beginning of a Settlement Period indicating the changes to the levels of Generation and Demand scheduled for that Settlement Period from that shown in the Final Day-Ahead Schedule.

Hourly Demand

The average of the instantaneous Demand integrated over a single clock hour, in MW.

Hourly Ex Post Price

The Energy-weighted average of the Dispatch Interval Ex Post Prices in each Zone during each Settlement Period. The Hourly Ex Post Price will vary between Zones when Congestion is present. This price is used in the Regulation Energy Payment Adjustment and in RMR settlements.

Hourly Pre-Dispatch

The process in which the ISO Dispatches Energy Bids from System Resources before the start of the next Settlement Period for the entire duration of that Settlement Period.

Hydro Spill Generation

Hydro-electric Generation in existence prior to the ISO Operations Date that: i) has no storage capacity and that, if backed down, would spill; ii) has exceeded its storage capacity and is spilling even though the generators are at full output, or iii) has inadequate storage capacity to prevent loss of hydro-electric Energy either immediately or during the forecast period, if hydro-electric Generation is reduced; iv) has increased regulated water output to avoid an impending spill.

Identification Code

An identification number assigned to each Scheduling Coordinator by the ISO.

Imbalance Energy

Imbalance Energy is Energy from Regulation, Spinning and Non-

Import Capability Load Share

Spinning Reserves, or Replacement Reserve, or Energy from other Generating Units, System Units, System Resources, or Loads that are able to respond to the ISO's request for more or less Energy. A Load Serving Entity's proportionate share of the forecasted RA Compliance Year coincident peak Demand for the ISO Control Area relative to the total coincident peak Demand for the ISO Control Area as determined by the California Energy Commission.

Import Capability Load Share Ratio

A Load Serving Entity's Import Capability Load Share divided by the sum of the Import Capability Load Shares of all Load Serving Entities with unfulfilled requests for import capability on a particular branch group.

Import Capability Transfer Registration Process

The electronic means by which Load Serving Entities and Market Participants must register with the ISO any bilateral transfers of Existing Contract Import Capability, Pre-RA Import Commitment Capability, or Remaining Import Capability.

Inactive Zone

All Zones which the ISO Governing Board has determined do not have a workably competitive Generation market and as set out in Appendix I to the ISO Tariff.

Incremental Change

The change in dollar value of a specific charge type from the Preliminary Settlement Statement to the Final Settlement Statement including any new charge types or Trading Day charges appearing for the first time on the Final Settlement Statement.

In-Service Date

The date upon which the Interconnection Customer reasonably expects it will be ready to begin use of the Participating TO Interconnection Facilities to obtain back feed power.

"Interim Black Start Agreement"

An agreement entered into between the ISO and a Participating Generator (other than a Reliability Must-Run Agreement) for the provision by the Participating Generator of Black Start capability and Black Start Energy on an interim basis until the introduction by the ISO of its Black Start auction (or until terminated earlier by either party in accordance with its terms).

Intermediary Control Area

Any Control Area between a Host Control Area and the ISO Control Area. An Intermediary Control Area may, or may not, be directly interconnected with the ISO Control Area.

**Instructed Imbalance
Energy**

The real-time change in Generation output or Demand (from dispatchable Generating Units, System Units, System Resources or Loads) which is instructed by the ISO to ensure that reliability of the ISO Control Area is maintained in accordance with Applicable Reliability Criteria. Sources of Imbalance Energy include Spinning and Non-Spinning Reserves, Replacement Reserve, and Energy from other dispatchable Generating Units, System Units, System Resources or Loads that are able to respond to the ISO's request for more or less Energy.

Inter-Scheduling

Ancillary Service transactions between Scheduling Coordinators.

Coordinator Ancillary

Service Trades

Inter-Scheduling

Energy transactions between Scheduling Coordinators.

Coordinator Energy

Trades

Inter-Zonal Congestion

Congestion across an Inter-Zonal Interface.

Inter-Zonal Interface

The (i) group of transmission paths between two adjacent Zones of the ISO Controlled Grid, for which a physical, non-simultaneous transmission capacity rating (the rating of the interface) has been established or will be established prior to the use of the interface for Congestion Management; (ii) the group of transmission paths between an ISO Zone and an adjacent Scheduling Point, for which a physical, non-simultaneous transmission capacity rating (the rating of the interface) has been established or will be established prior to the use of the interface for Congestion Management; (iii) the group of transmission paths between two adjacent Scheduling Points, where the group of paths has an established transfer capability and established transmission rights; or (iv) the Miguel or South of Lugo constraints whenever Congestion Management is necessary to mitigate Congestion due to flow from one or more Scheduling Points from adjacent Zones and/or due to generation within that Zone.

Interconnection

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

**Interconnection
Agreement**

A contract between a party requesting interconnection and the Participating TO that owns the transmission facility with which the requesting party wishes to interconnect.

<u>Interconnection Customer</u>	Any entity, including a Participating TO or any of its Affiliates or subsidiaries, that proposes to interconnect its Generating Facility with the ISO Controlled Grid.
<u>Interconnection Customer's Interconnection Facilities</u>	All facilities and equipment, as identified in Part A of the Standard Large Generator Interconnection Agreement, that are located between the Generating Facility and the Point of Change of Ownership, including any modification, addition, or upgrades to such facilities and equipment necessary to physically and electrically interconnect the Generating Facility to the ISO Controlled Grid. Interconnection Customer's Interconnection Facilities are sole use facilities.
<u>Interconnection Facilities</u>	The Participating TO's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the ISO Controlled Grid. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades, Stand Alone Network Upgrades or Network Upgrades.
<u>Interconnection Facilities Study</u>	A study conducted by the Participating TO(s), ISO, or a third party consultant for the Interconnection Customer to determine a list of facilities (including the Participating TO's Interconnection Facilities, Network Upgrades, and Distribution Upgrades), the cost of those facilities, and the time required to interconnect the Generating Facility with the ISO Controlled Grid. The scope of the study is defined in Section 8 of the Standard Large Generator Interconnection Procedures.
<u>Interconnection Facilities Study Agreement</u>	The form of agreement accepted by FERC and posted on the ISO Home Page for conducting the Interconnection Facilities Study.
<u>Interconnection Feasibility Study</u>	A preliminary evaluation conducted by the Participating TO(s), ISO, or a third party consultant for the Interconnection Customer of the system impact and cost of interconnecting the Generating Facility to the ISO Controlled Grid, the scope of which is described in Section

Interconnection Feasibility

6 of the Standard Large Generator Interconnection Procedures.

Study Agreement

The form of agreement accepted by FERC and posted on the ISO Home Page for conducting the Interconnection Feasibility Study.

Interconnection Handbook

A handbook, developed by the Participating TO and posted on the Participating TO's web site or otherwise made available by the Participating TO, describing technical and operational requirements for wholesale generators and loads connected to the Participating TO's portion of the ISO Controlled Grid, as such handbook may be modified or superseded from time to time. Participating TO's standards contained in the Interconnection Handbook shall be deemed consistent with Good Utility Practice and Applicable Reliability Criteria. In the event of a conflict between the terms of the LGIP or SGIP and the terms of the Participating TO's Interconnection Handbook, the terms in the LGIP or SGIP shall apply.

Interconnection Request

An Interconnection Customer's request, in the form of Part 1 to the Standard Large Generator Interconnection Procedures or Attachment 2 to the Small Generator Interconnection Procedures, in accordance with Section 25.1 of the ISO Tariff.

Interconnection Service

The service provided by the Participating TO and ISO associated with interconnecting the Interconnection Customer's Generating Facility to the ISO Controlled Grid and enabling it to receive electric energy and capacity from the Generating Facility at the Point of Interconnection, pursuant to the terms of the Standard Large Generator Interconnection Agreement, the Participating TO's TO Tariff, and the ISO Tariff.

Interconnection Study

Any of the following studies: the Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study described in the Standard Large Generator Interconnection Procedures.

Interconnection System

Impact Study

An engineering study conducted by the Participating TO(s), ISO, or a third party consultant for the Interconnection Customer that evaluates the impact of the proposed interconnection on the safety and reliability of the ISO Controlled Grid and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the Generating Facility were

interconnected without project modifications or system modifications, focusing on the Adverse System Impacts identified in the Interconnection Feasibility Study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting as described in the Standard Large Generator Interconnection Procedures.

**Interconnection System
Impact Study Agreement**

The form of agreement accepted by FERC and posted on the ISO Home Page for conducting the Interconnection System Impact Study.

Interest

Interest shall be calculated in accordance with the methodology specified for interest on refunds in the regulations of FERC at 18 C.F.R. §35.19(a)(2)(iii) (1996). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment, except as provided in Section 11.2.1. When payments are made by mail, bills shall be considered as having been paid on the date of receipt.

Interruptible Imports

Energy sold by a Generator or resource located outside the ISO Controlled Grid which by contract can be interrupted or reduced at the discretion of the seller.

Intra-Zonal Congestion

Congestion within a Zone.

IOU

An investor owned electric utility.

**ISO (Independent System
Operator)**

The California Independent System Operator Corporation, a state chartered, nonprofit corporation that controls the transmission facilities of all Participating TOs and dispatches certain Generating Units and Loads.

ISO Account

The ISO Clearing Account, the ISO Reserve Account or such other trust accounts as the ISO deems necessary or convenient for the purpose of efficiently implementing the funds transfer system under the ISO Tariff.

ISO ADR Committee

The Committee appointed by the ISO ADR Committee pursuant to Article IV, Section 3 of the ISO bylaws to perform functions assigned to the ISO ADR Committee in the ADR process in Section 13 of the ISO Tariff.

ISO ADR Procedures

The procedures for resolution of disputes or differences set out in Section 13 of the ISO Tariff, as amended from time to time.

**ISO 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

The meter service agreements between the ISO and ISO Metered Entities.

Service Agreements

ISO Operations Date

The date on which the ISO first assumes Operational Control of the ISO Controlled Grid.

ISO Outage Coordination

The office established by the ISO to coordinate Maintenance Outages in accordance with Section 9.3 of the ISO Tariff.

Office

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.

ISO-WECC Billing Services Agreement

The agreement between the ISO and the WECC entered into by those parties in August 2007, as it may be amended from time to time, regarding the ISO's performance of certain billing services to facilitate the WECC's collection of NERC/WECC Charges.

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.

LARN Report for 2006

The report, published by the ISO, which identifies each Local Reliability Area for 2006 and the contingencies that require the ISO to specify a geographically contiguous area as a Local Reliability Area, and the amount of generation (in MW) needed for each Local Reliability Area in order to satisfy Applicable Reliability Criteria, taking into account Non-Generation Solutions.

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 Share Quantity The product of Total Import Capability and Import Capability Load Share.

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 Area

For 2006, a geographically contiguous area within a TAC Area that the CAISO has determined, through reliability studies, requires resources that are effective to meet Applicable Reliability Criteria.

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

	the control of the ISO.
<u>Local Reliability Criteria</u>	Reliability Criteria established at the ISO Operations Date, unique to the transmission systems of each of the Participating TOs.
<u>Local Resource Adequacy Requirement Deficiency</u>	The difference in MWs, as determined under Section 40.7 of Appendix CC following the opportunity to resolve deficiencies that is provided under Section 40.7 of Appendix CC, between (1) the allocated responsibility for Local Capacity Area Resources under Section 40.3.2 of Appendix CC of a Scheduling Coordinator for an RA Entity and (2) the Net Qualifying Capacity of the Local Capacity Area Resources identified in the annual Resource Adequacy Plan submitted by that Scheduling Coordinator pursuant to Sections 40.2.1.1, 40.2.2.4, 40.2.3.4, or 40.2.4 of Appendix CC.
<u>Location Code</u>	The code assigned by the ISO to Generation input points, and Demand Take-Out Points from the ISO Controlled Grid, and transaction points from trades between Scheduling Coordinators. This will be the information used by the ISO Controlled Grid, and transaction points for trades between Scheduling Coordinators. This will be the information used by the ISO to determine the location of the input, output, and trade points of Energy Schedules. Each Generation input and Demand Take-Out Point will have a designated Location Code identification for use in submitting Energy and Ancillary Service bids and Schedules.
<u>Location Constrained Resource Interconnection Facility (LCRIF)</u>	A High Voltage Transmission Facility that has been determined by the CAISO to satisfy all of the requirements of Section 24.1.3.

Location Constrained

A Generating Unit that (a) uses a primary fuel source or source of energy that is in a fixed location and cannot practicably be transported from that location; and (b) is located in an Energy Resource Area. Generating Units meeting criterion (a) shall include, but not be limited to, wind, solar, geothermal, hydroelectric, digester gas, landfill gas, ocean wave and ocean thermal tidal current Generating Units.

Resource Interconnection

Generator (LCRIG)

Loop Flow

Energy flow over a transmission system caused by parties external to that system.

Loss Scale Factor

The ratio of expected Transmission Losses to the total Transmission Losses which would be collected if Full Marginal Loss Rates were utilized.

Low Voltage Access Charge

The Access Charge applicable under Section 26.1 to recover the Low Voltage Transmission Revenue Requirement of a Participating TO.

Low Voltage

Transmission Facility

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

Low Voltage

Transmission Revenue

Requirement

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

**Low Voltage Wheeling
Access Charge**

The Wheeling Access Charge associated with the recovery of a Participating TO's Low Voltage Transmission Revenue Requirement in accordance with Section 26.1.

Maintenance Outage

A period of time during which an Operator (i) takes its transmission facilities out of service for the purposes of carrying out routine planned maintenance, or for the purposes of new construction work or for work on de-energized and live transmission facilities (e.g., relay maintenance or insulator washing) and associated equipment; or (ii) limits the capability of or takes its Generating Unit or System Unit out of service for the purposes of carrying out routine planned maintenance, or for the purposes of new construction work.

Market Behavior Rules

Those rules established by FERC under Docket No. EL01-118.

Market Clearing Price

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

Market Manipulation

Has the meaning set forth in Section 37.7.

Market Monitoring Unit

The component of the ISO organization (currently the "Department of Market Monitoring") that is assigned responsibility in the first instance for the functions of a Market Monitoring Unit, as that term is used in Docket No. EL01-118.

Market Participant

An entity, including a Scheduling Coordinator, who either: (1) participates in the Energy marketplace through the buying, selling, transmission, or distribution of Energy or Ancillary Services into, out of, or through the ISO Controlled Grid; or (2) is a CRR Holder or Candidate CRR Holder.

**Market Surveillance
Committee (MSC)**

The committee established under Appendix P.2.

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

A modification that has a material impact on the cost or timing of any Interconnection Request or any other valid interconnection request with a later queue priority date.

Maximum Import Capability

A quantity in MW determined by the ISO for each branch group into the ISO Control Area to be deliverable to the ISO Control Area based on ISO study criteria.

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, MVA_r and MVA_h.

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.

Month-Ahead System

Resource Adequacy

Requirements

The amount of Qualifying Capacity that a RA Entity must reflect in its monthly Resource Adequacy Plan submitted pursuant to Section 40.2.2 in compliance with Resource Adequacy Rules adopted by the CPUC or a Local Regulatory Authority, as applicable.

<u>Month-Ahead System</u>	The monthly deficiency in meeting the Month-Ahead System
<u>Resource Deficiency</u>	Resource Adequacy Requirements as determined under Section 40.7 of Appendix CC following the opportunity to resolve deficiencies that is provided under Section 40.7 of Appendix CC.
<u>Monthly Peak Load</u>	The maximum hourly Demand on a Participating TO's transmission system for a calendar month, multiplied by the Operating Reserve Multiplier.
<u>Monthly TCPM Charge</u>	The monthly charge determined in accordance with Appendix F, Schedule 6.
<u>MRTU Tariff</u>	The ISO Tariff that will implement the ISO's Market Redesign and Technology Upgrade ("MRTU").

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 Capacity

The payment made in accordance with Section 40.14 of this ISO Tariff.

Payment

Nationally Recognized

National credit rating agencies as designated by the U.S.

Statistical Rating

Securities & Exchange Commission.

Organizations (NRSRO)

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 Corporation or its successor.

NERC/WECC Charge

A given year for which NERC/WECC Charges will be assessed by the WECC based on data from the calendar year two years prior to the year of the NERC/WECC Charge assessment.

Assessment Year

NERC/WECC Charges

The charges approved by FERC, pursuant to Section 215 of the FPA and FERC issuances related thereto, that provide funding for the statutory-related functions performed by NERC, the WECC, and regional advisory bodies that serve the WECC, or their successors or assignees.

NERC/WECC Charge

An account to be established by the ISO for the purpose of maintaining funds collected from Scheduling Coordinators and disbursing such funds to the WECC.

Trust Account

NERC/WECC Metered Demand

For purposes of calculating NERC/WECC Charges, a Scheduling Coordinator's net metered CAISO Demand plus Unaccounted for Energy for net metered CAISO Demand and Transmission Losses for metered CAISO Demand. A Scheduling Coordinator's net metered CAISO Demand equals the Scheduling Coordinator's metered CAISO Demand (which adds Energy associated with imports from and subtracts Energy associated with exports to other balancing authority areas), less metered CAISO Demand for Station Power and for Energy required for storage at electric energy storage facilities, such as pumped storage. For purposes of calculating NERC/WECC Metered Demand, Unaccounted for Energy and Transmission Losses allocable to net metered CAISO Demand will be allocated pro rata to each Scheduling Coordinator based on the Scheduling Coordinator's net metered CAISO Demand.

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 controlled Grid required at or beyond the Point of Interconnection to accommodate the interconnection of the Generating Facility to the ISO Controlled Grid. Network Upgrades shall consist of Delivery Network Upgrades and Reliability Network Upgrades. Network Upgrades do not include Distribution 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-Generation Solutions

Solutions proposed by a PTO or an RA Entity that satisfy local area reliability needs of the ISO which serve as an alternative to generation capacity, including equipment upgrades, operating procedures such as switching, manual Load shedding or automatic Load shedding, and other operational strategies or tools.

Non-Load-Serving

Participating TO

A Participating TO that (1) is not a UDC, MSS Operator or Scheduling Coordinator serving End-Use Customers and (2) does not have Gross Load in accordance with Section 9 of Schedule 3 of Appendix F.

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

	operation of the ISO Control Area.
<u>Operating Transfer Capability</u>	The maximum capability of a transmission path to transmit real power, expressed in MW, at a given point in time.
<u>Operational Control</u>	The rights of the ISO under the Transmission Control Agreement and the ISO Tariff to direct Participating TOs how to operate their transmission lines and facilities and other electric plant affecting the reliability of those lines and facilities for the purpose of affording comparable non-discriminatory transmission access and meeting Applicable Reliability Criteria.
<u>Operator</u>	The operator of facilities that comprise the ISO Controlled Grid or a Participating Generator.
<u>OPF (Optimal Power Flow)</u>	A computer optimization program which uses a set of control variables (which may include active power and/or reactive power controls) to determine a steady-state operating condition for the transmission grid for which a set of system operating Constraints (which may include active power and/or reactive power constraints) are satisfied and an objective function (e.g. total cost or shift of schedules) is minimized.
<u>Optional Interconnection Study</u>	A sensitivity analysis based on assumptions specified by the Interconnection Customer in the Optional Interconnection Study Agreement.
<u>Optional Interconnection Study Agreement</u>	The form of agreement accepted by FERC and posted on the ISO Home Page for conducting the Optional Interconnection Study.
<u>Order No. 888</u>	The final rule issued by FERC entitled "Promoting Wholesale Competition through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs., Regulations Preambles [1991-1996] ¶ 31,036 (1996), Order on Rehearing, Order No. 888-A, 78 FERC ¶ 61,220 (1997), as it may be amended from time to time
<u>Order No. 889</u>	The final rule issued by FERC entitled "Open Access Same-Time Information System (formerly Real Time Information Networks) and Standards of Conduct," 61 Fed. Reg. 21,737

(May 10, 1996), FERC Stats. & Regs., Regulations Preambles [1991-1996] ¶ 31,035 (1996), Order on Rehearing, Order No. 889-A, 78 FERC ¶ 61,221 (1997), as it may be amended from time to time.

Original Participating TO

A Participating TO that was a Participating TO as of January 1, 2000.

Outage

Disconnection, separation or reduction in capacity, planned or forced, of one or more elements of an electric system.

Overgeneration

A condition that occurs when total Generation exceeds total Demand in the ISO Control Area.

Participant

- (a) Scheduling Coordinators (SCs);
- (b) Utility Distribution Companies (UDCs);
- (c) Participating Transmission Owners (PTOs);
- (d) Participating Generators;
- (e) Control Area Operators, to the extent the agreement between the Control Area Operator and the ISO so provides; and
- (f) Metered Subsystem (MSS) Operators.

Participating Buyer

A Direct Access End-User or a wholesale buyer of Energy or Ancillary Services through Scheduling Coordinators.

Participating Intermittent Resource

One or more Eligible Intermittent Resources that meets the requirements of the technical standards for Participating Intermittent Resources adopted by the ISO and published on the ISO Home Page.

Participating Intermittent Resource Export Fee

Fee based on Schedule 4 of Appendix F and EIRP 5.3.

Participating Intermittent Resource Fees

Fees set forth in Section 11.2.4.5.4 of the ISO Tariff

Participating Load

An entity providing Curtailable Demand, which has undertaken in writing to comply with all applicable provisions of the ISO Tariff, as they may be amended from time to time.

Participating Seller or

A Generator or other seller of Energy or Ancillary Services

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 or Attachment 3 to the Small 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
NERC/WECC Charge
Invoice**

An initial invoice issued by the ISO that reflects an allocation of NERC/WECC Charges to a Scheduling Coordinator for a NERC/WECC Charge Assessment Year based on (i) the Scheduling Coordinator's NERC/WECC Metered Demand for the NERC/WECC Charge Assessment Year as described in Section 11.2.19.4, multiplied by (ii) the Preliminary NERC/WECC Charge Rate for the NERC/WECC Charge Assessment Year.

**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.

**Preliminary NERC/WECC
Charge Rate**

The preliminary rate to be paid by Scheduling Coordinators for NERC/WECC Charges for a NERC/WECC Charge Assessment Year based on (i) the portions of the proposed budgets of NERC, WECC, and regional advisory bodies that serve the WECC that the WECC notifies the ISO in writing are allocable to the ISO for the NERC/WECC Charge Assessment Year or, alternatively, if the WECC does not provide such written notification to the ISO in accordance with the ISO-WECC Billing Services Agreement, the portions of the budgets of NERC, WECC, and regional advisory bodies that serve that WECC that the WECC informed the ISO were allocable to the ISO for the immediately preceding NERC/WECC Charge Assessment Year divided by (ii) the total of all Scheduling Coordinators' NERC/WECC Metered Demand for the NERC/WECC Charge Assessment Year as described in Section 11.2.19.4, including any adjustments to the calculation of NERC/WECC Metered Demand, as reported to the WECC pursuant to Section 11.2.19.4(b), and including any additional adjustments to the calculation of NERC/WECC Metered Demand, based on decisions by the WECC to permit such adjustments, that the WECC provides to the ISO in a written statement in accordance with the ISO-WECC Billing Services Agreement.

**Pre-RA Import
Commitment Capability**

The quantity in MW assigned to a particular branch group into the ISO Control Area based on a Pre-RA Import Commitment.

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 provide 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.

RA Compliance Year

Calendar year from January 1 to December 31.

RA Entity

Any entity identified in Section 40.1 of the ISO Tariff.

RA Entity Load Share

Percentage

An RA Entity's proportionate share of load in a TAC Area. The RA Entity Load Share Percentage shall be calculated for each RA Entity by dividing the RA Entity's actual annual coincident peak Load in each TAC area in 2005 by the total coincident peak Load of all RA Entities in the TAC Area in 2005.

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.

Regulation

The service provided either by Generating Units certified by the ISO as equipped and capable of responding to the ISO's direct digital control signals, or by System Resources that have been certified by the ISO as capable of delivering such service to the ISO Control Area, in an upward and downward direction to match, on a real-time basis, Demand and resources, consistent with established NERC and WECC operating criteria.

Regulation is used to control the power output of electric generators within a prescribed area in response to a change in system frequency, tieline loading, or the relation of these to each other so as to maintain the target system frequency and/or the established interchange with other areas within the predetermined limits. Regulation includes both the increase of output by a Generating Unit or System Resource ("Regulation Up") and the decrease in output by a Generating Unit or System Resource ("Regulation Down"). Regulation Up and Regulation Down are distinct capacity products, with separately stated requirements and Market Clearing Prices in each Settlement Period.

Regulation Energy

The additional value of regulating Energy.

Payment Adjustment

Regulatory Must-Run

Generation

Hydro Spill Generation and Generation which is required to run by applicable Federal or California laws, regulations, or other governing jurisdictional authority. Such requirements include but are not limited to hydrological flow requirements, environmental requirements, such as minimum fish releases, fish pulse releases and water quality requirements, irrigation and water supply requirements of solid waste Generation, or other Generation contracts specified or designated by the jurisdictional regulatory authority as it existed on December 20, 1995, or as revised by Federal or California law or Local Regulatory Authority.

Regulatory Must-Take

Generation

Those Generation resources identified by CPUC, or a Local Regulatory Authority, the operation of which is not subject to competition. These resources will be scheduled by the relevant Scheduling Coordinator directly with the ISO on a must-take basis. Regulatory Must-Take Generation includes qualifying

	facility Generating Units as defined by federal law, nuclear units and pre-existing power purchase contracts with minimum energy take requirements.
<u>Reliability Coordinator</u>	The person responsible for Security Monitoring in real time for the California Area.
<u>Reliability Criteria</u>	Pre-established criteria that are to be followed in order to maintain desired performance of the ISO Controlled Grid under contingency or steady state conditions.
<u>Reliability Must-Run Charge (RMR Charge)</u>	The sum payable by a Responsible Utility to the ISO pursuant to Section 30.6.1.1 of the ISO Tariff for the costs, net of all applicable credits, incurred under the RMR Contract.
<u>Reliability Must-Run Contract (RMR Contract)</u>	A Must-Run Service Agreement between the owner of an RMR Unit and the ISO.
<u>Reliability Must-Run Generation (RMR Generation)</u>	Generation that the ISO determines is required to be on line to meet Applicable Reliability Criteria requirements. This includes i) Generation constrained on line to meet NERC and WECC reliability criteria for interconnected systems operation; ii) Generation needed to meet Load demand in constrained areas; and iii) Generation needed to be operated to provide voltage or security support of the ISO or a local area.
<u>Reliability Must-Run Unit (RMR Unit)</u>	A Generating Unit which is the subject of a Reliability Must-Run Contract.
<u>Reliability Network Upgrades</u>	The transmission facilities at or beyond the Point of Interconnection necessary to interconnect a Large Generating Facility safely and reliably to the ISO Controlled Grid, which would not have been necessary but for the interconnection of the Large Generating Facility, including Network Upgrades necessary to remedy short circuit or stability problems resulting from the interconnection of the Large Generating Facility to the ISO Controlled Grid. Reliability Network Upgrades also include, consistent with WECC practice, the facilities necessary to mitigate any adverse impact the Large Generating Facility's interconnection may have on a path's WECC rating.
<u>Reliability Services Costs</u>	The costs associated with services provided by the ISO: 1) that

are deemed by the ISO as necessary to maintain reliable electric service in the ISO Control Area; and 2) whose costs are billed by the ISO to the Participating TO pursuant to the ISO Tariff.

Reliability Services Costs include costs charged by the ISO to a Participating TO associated with service provided under an RMR Contract (Section 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)

Remaining Import Capability

The quantity in MW of Total Import Capability assigned to a Load Serving Entity up to its Load Share Quantity after the assignment of Existing Contract Import Capability and Pre-RA Import Commitment. Capability.

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

A resource that is required to offer Resource Adequacy Capacity.

Resource

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)

The security constrained optimal dispatch and ex post pricing

Software

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

A computer system that allows an electric system operator to remotely monitor and control elements of an electric system.

Acquisition)

SC-RA Entity

A Scheduling Coordinator for an RA Entity.

Scheduling Coordinator

An agreement between a Scheduling Coordinator and the ISO

Agreement

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

An applicant for certification by the ISO as a Scheduling Coordinator.

Applicant

Scheduling Coordinator

The form specified by the ISO from time to time in which a Scheduling

Application Form

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.

<u>Schedule</u>	A statement of (i) Demand, including quantity, duration and Take-Out Points and (ii) Generation, including quantity, duration, location of Generating Unit, and Transmission Losses; and (iii) Ancillary Services which will be self-provided, (if any) submitted by a Scheduling Coordinator to the ISO. "Schedule" includes Preferred Schedules, Suggested Adjusted Schedules, Final Schedules and Revised Schedules.
<u>Scheduled Maintenance</u>	Maintenance on Participating Generators, TOs and UDC facilities scheduled more than twenty-four hours in advance.
<u>Scheduling Coordinator (SC)</u>	An entity certified by the ISO for the purposes of undertaking the functions specified in Section 4.5.3 of the ISO Tariff.
<u>Scheduling Coordinator Metered Entity</u>	A Generator, Eligible Customer or End-User that is not an ISO Metered Entity.
<u>Scheduling Point</u>	A location at which the ISO Controlled Grid is connected, by a group of transmission paths for which a physical, non-simultaneous transmission capacity rating has been established for Congestion Management, to transmission facilities that are outside the ISO's Operational Control. A Scheduling Point typically is physically located at an "outside" boundary of the ISO Controlled Grid (e.g., at the point of interconnection between a Control Area utility and the ISO Controlled Grid). For most practical purposes, a Scheduling Point can be considered to be a Zone that is outside the ISO's Controlled Grid.
<u>Scoping Meeting</u>	The meeting among representatives of the Interconnection Customer, the applicable Participating TO, and the ISO conducted for the purpose of discussing alternative interconnection options, to exchange information including any transmission data and earlier study evaluations that would be reasonably expected to impact such interconnection options, to analyze such information, and to determine the potential feasible Points of Interconnection.
<u>Security</u>	The form of security provided by a Scheduling Coordinator pursuant to Section 12.1 of the ISO Tariff (i.e., letter of credit, guarantee or cash deposit) to secure its trading obligations.
<u>Security Monitoring</u>	The real-time assessment of the ISO Controlled Grid that is conducted to ensure that the system is operating in a secure state, and in compliance with all Applicable Reliability Criteria.
<u>Service Area</u>	An area in which an IOU or a Local Publicly Owned Electric Utility is

	obligated to provide electric service to End-Use Customers.
<u>Set Point</u>	Scheduled operating level for each Generating Unit or other resource scheduled to run in the Hour-Ahead Schedule.
<u>Settlement</u>	Process of financial settlement for products and services purchased and sold undertaken by the ISO under Section 11 of the ISO Tariff. Each Settlement will involve a price and a quantity.
<u>Settlement Account</u>	An Account held at a bank situated in California, designated by a Scheduling Coordinator or a Participating TO pursuant to the Scheduling Coordinator's Scheduling Coordinator Agreement or in the case of a Participating TO, Section 2.2.1 of the TCA, to which the ISO shall pay amounts owing to the Scheduling Coordinator or the Participating TO under the ISO Tariff.
<u>Settlement Interval</u>	The time period, which is equal to or a multiple of the Dispatch Interval, over which the ISO settles deviations in Generation and Demand from Final Hour-Ahead Schedules.
<u>Settlement Period</u>	For all ISO transactions the period beginning at the start of the hour, and ending at the end of the hour. There are twenty-four Settlement Periods in each Trading Day, with the exception of a Trading Day in which there is a change to or from daylight savings time.
<u>Settlement Quality Meter Data</u>	Meter Data gathered, edited, validated, and stored in a settlement-ready format, for Settlement and auditing purposes.
<u>Settlement Statement</u>	Either or both of a Preliminary Settlement Statement or Final Settlement Statement.
<u>Settlement Statement Re-run</u>	The re-calculation of a Settlement Statement in accordance with the provisions of the ISO Tariff.
<u>Settlements, Metering, and Client Relations Charge</u>	The component of the Grid Management Charge that provides for the recovery of the ISO's costs, including, but not limited to the costs of maintaining customer account data, providing account information to customers, responding to customer inquiries, calculating market charges, resolving customer disputes, and the costs associated with the ISO's Settlement, billing, and metering activities. Because this is a fixed charge per Scheduling Coordinator ID, costs associated with activities listed above also are allocated to other charges under the Grid Management Charge according to formula set forth in Appendix F, Schedule 1, Part A of this Tariff.
<u>Severance Fee</u>	The charge or periodic charge assessed to customers to recover the

reasonable uneconomic portion of costs associated with Generation-related assets and obligations, nuclear decommissioning, and capitalized Energy efficiency investment programs approved prior to August 15, 1996 and as defined in the California Assembly Bill No. 1890 approved by the Governor on September 23, 1996.

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**

The form of interconnection agreement applicable to an Interconnection Request pertaining to a Large Generating Facility.

(LGIA)

**Standard Large Generator
Interconnection**

The ISO Protocol that sets forth the interconnection procedures applicable to an Interconnection Request pertaining to a Large

Procedures

Generating Facility that is included in the ISO Tariff.

(LGIP)

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

The trust account established in accordance with Section 40.12.2.

Account

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.

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.

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.

TCPM

The Transitional Capacity Procurement Mechanism contained in Section 43.

TCPM Capacity

Eligible Capacity that has been designated under the TCPM.

TCPM Capacity Payment

The payment provided pursuant to Section 43.7.1 of the ISO Tariff.

TCPM Significant Event

A Significant Event is a substantial event, or a combination of events, that is determined by the ISO to either result in a material difference from what was assumed in the RA program for purposes of determining the RA capacity requirements, or produce a material change in system conditions or in ISO-Controlled Grid Operations, that causes, or threatens to cause, a failure to meet Reliability Criteria absent the recurring use of a non-RA resource(s) on a prospective basis.

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 Import Capability

The aggregate Maximum Import Capability of all branch groups into the ISO Control Area in MW deliverable to the ISO Control Area based on ISO study criteria minus the aggregate sum in MW of all Existing Contracts and Transmission Ownership Rights held by load serving entities that do not serve Load within the ISO Control Area.

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 CAISO for Wheeling service, FTR auction revenue and Usage Charges, plus (a) the revenues received from any LCRIG with respect to an LCRIF, unless FERC has approved an alternative mechanism to credit such revenues against the Original Participating TO's TRR, and (b) the shortfall or surplus resulting from any cost differences between Transmission Losses and Ancillary Service requirements associated with Existing Rights and the CAISO's rules and protocols, minus any Low Voltage Access Charge amounts paid for the use of the Low Voltage Transmission Facilities of a Non-Load-Serving Participating TO pursuant to Section 26.1 and Appendix F, Schedule 3, Section 13. For a New Participating TO during the 10-year transition period described in Section 4 of Schedule 3 of Appendix F, the revenues received from the CAISO for Wheeling service and Net FTR Revenue, plus (a) the revenues received from any LCRIG with respect to an LCRIF, unless FERC has approved an alternative mechanism to credit such revenues against the New Participating TO's TRR, and (b) the shortfall or surplus resulting from any cost differences between Transmission Losses and Ancillary Service requirements associated with Existing Rights and the CAISO's rules and protocols, minus any Low Voltage Access Charge amounts paid for the use of the Low Voltage Transmission Facilities of a Non-Load-Serving Participating TO pursuant to Section 26.1 and Appendix F, Schedule 3, Section 13. 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, 8, and 13 of Appendix F, Schedule 3, flow through to transmission customers.

**TRR (Transmission
Revenue Requirement)**

The TRR is the total annual authorized revenue requirements associated with transmission facilities and Entitlements turned over to the Operational Control of the ISO by a Participating TO. The costs of any transmission facility turned over to the Operational Control of the ISO shall be fully included in the Participating TO's TRR. The TRR includes the costs of transmission facilities and Entitlements and deducts Transmission Revenue Credits and credits for Standby Transmission Revenue and the transmission revenue expected to be actually received by the Participating TO for Existing Rights and Converted Rights.

Trial Operation

The period during which Interconnection Customer is engaged in on-

site test operations and commissioning of a Generating Unit prior to Commercial Operation.

Trustee

The trustee of the California Independent System Operator trust established by order of the California Public Utilities Commission on August 2, 1996 Decision No. 96-08-038 relating to the Ex Parte Interim Approval of a Loan Guarantee and Trust Mechanism to Fund the Development of an Independent System Operator (ISO) and a Power Exchange (PX) pursuant to Decision 95-12-063 as modified.

UDC (Utility Distribution Company)

An entity that owns a Distribution System for the delivery of Energy to and from the ISO Controlled Grid, and that provides regulated retail electric service to Eligible Customers, as well as regulated procurement service to those End-Use Customers who are not yet eligible for direct access, or who choose not to arrange services through another retailer.

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

The penalty as set forth in Section 11.2.4.1.2 of this ISO Tariff.

Penalty

Uninstructed Imbalance

The real-time change in Generation or Demand other than that

<u>Energy</u>	instructed by the ISO or which the ISO Tariff provides will be paid at the price for Uninstructed Imbalance Energy.
<u>Unit Commitment</u>	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).
<u>Unrated Governmental Entity</u>	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.
<u>Unrated Public/Private Corporation</u>	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.
<u>Un-Recovered Minimum Load Cost</u>	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.
<u>Unsecured Credit Limit</u>	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.
<u>Upgrades</u>	The required additions and modifications to the ISO Controlled Grid and the Distribution System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.
<u>Usage Charge</u>	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.
<u>Validation, Estimation and Editing (VEE)</u>	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 Western Path 15

A network of transmission lines embodied within the WECC region. 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

Agreement

Agreement dated June 18, 1999 among the WSCC and certain of its Member transmission operators, as such may be amended from time to time.

**Year-Ahead System
Resource Adequacy
Requirements**

The amount of Qualifying Capacity that a RA Entity must reflect in its year-ahead Resource Adequacy Plan submitted pursuant to Section 40.2.1 in compliance with Resource Adequacy Rules adopted by the CPUC or a Local Regulatory Authority, as applicable.

**Year-Ahead System
Resource Deficiency**

The monthly deficiency in meeting Year-Ahead System Resource Adequacy Requirements as determined under Section 40.7 of Appendix CC following the opportunity to resolve deficiencies that is provided under Section 40.7 of Appendix CC.

Zone

A portion of the ISO Controlled Grid within which Congestion is expected to be small in magnitude or to occur infrequently. "Zonal" shall be construed accordingly.

**Zonal Settlement Interval
Ex Post Price**

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

ISO TARIFF APPENDIX B
Pro Forma Agreements

ISO TARIFF APPENDIX B.1
Scheduling Coordinator Agreement

Appendix B.1

Scheduling Coordinator Agreement

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

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

and

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

Whereas:

- A. The Scheduling Coordinator has applied for certification by the ISO under the certification procedure referred to in Section 4.5.1 of the ISO Tariff.
- B. The Scheduling Coordinator wishes to schedule Energy and Ancillary Services on the ISO Controlled Grid under the terms and conditions set forth in the ISO Tariff.

NOW IT IS HEREBY AGREED as follows:

CHAPTER 1 DEFINITIONS

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

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

CHAPTER 2 COVENANT OF THE SCHEDULING COORDINATOR

The Scheduling Coordinator agrees that:

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

it will abide by, and will perform all of the obligations under the ISO Tariff placed on Scheduling Coordinators in respect of all matters set forth therein including, without limitation, all matters relating to the scheduling of Energy and Ancillary Services on the ISO Controlled Grid, ongoing obligations in respect of scheduling, Settlement, system security policy and

procedures to be developed by the ISO from time to time, billing and payments, confidentiality and dispute resolution;

it shall ensure that each UDC, over whose Distribution System Energy or Ancillary Services are to be transmitted in accordance with Schedules, Adjustment Bids or bids for Ancillary Services submitted to the ISO by the Scheduling Coordinator, enters into a UDC operating agreement in accordance with Section 4.4 of the ISO Tariff;

it shall ensure that each Generator for which it schedules Energy or on whose behalf it submits to the ISO Adjustment Bids or bids for Ancillary Services enters into a Generator agreement in accordance with Section 4.6 of the ISO Tariff;

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

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

CHAPTER 3 TERM AND TERMINATION

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

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

CHAPTER 4 ASSIGNMENT

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

PARTIAL INVALIDITY

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

CHAPTER 5 SETTLEMENT ACCOUNT

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

CHAPTER 6 NOTICES

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

ISO:

Name of Primary Representative: _____

Name of Alternative Representative: _____

Address: _____

State: _____ Zip Code: _____

E-Mail Address: _____

Phone No: _____

Fax No: _____

Scheduling Coordinator:

Name of Primary Representative: _____

Name of Alternative Representative: _____

Address: _____

State: _____ Zip Code: _____

E-Mail Address: _____

Phone No: _____

Fax No: _____

Settlement Account No: _____

Title: _____

Sort Code: _____

Bank: _____

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

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

9. **Electronic Contracting.**

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

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

ISO:

By: _____
Name Title Date

Scheduling Coordinator:

By: _____
Name Title Date

ISO TARIFF APPENDIX B.2
Participating Generator Agreement

CALIFORNIA INDEPENDENT SYSTEM OPERATOR

AND

[PARTICIPATING GENERATOR]

PARTICIPATING GENERATOR AGREEMENT

PARTICIPATING GENERATOR AGREEMENT (PGA)

THIS AGREEMENT is dated this ____ day of _____, _____ and is entered into, by and between:

(1) **[Full Legal Name]** having its registered and principal place of business located at **[Address]** (the "Participating Generator");

and

(2) **California Independent System Operator Corporation**, a California nonprofit public benefit corporation having a principal executive office located at such place in the State of California as the ISO Governing Board may from time to time designate, initially 151 Blue Ravine Road, Folsom, California 95630 (the "ISO").

The Participating Generator and the ISO are hereinafter referred to as the "Parties".

Whereas:

- A.** The ISO Tariff provides that the ISO shall not schedule Energy or Ancillary Services generated by any Generating Unit interconnected to the ISO Controlled Grid, or to the Distribution System of a Participating TO or of a UDC otherwise than through a Scheduling Coordinator.
- B.** The ISO Tariff further provides that the ISO shall not be obliged to accept Schedules or Adjustment Bids or bids for Ancillary Services relating to Generation from any Generating Unit interconnected to the ISO Controlled Grid unless the relevant Generator undertakes in writing to the ISO to comply with all applicable provisions of the ISO Tariff.
- C.** The Participating Generator wishes to be able to Schedule Energy and to submit Adjustment Bids, Supplemental Energy bids and bids for Ancillary Services to the ISO through a Scheduling Coordinator and, therefore, wishes to undertake to the ISO that it will comply with the applicable provisions of the ISO Tariff.
- D.** The Parties are entering into this Agreement in order to establish the terms and conditions on which the ISO and the Participating Generator will discharge their respective duties and responsibilities under the ISO Tariff.

NOW THEREFORE, in consideration of the mutual covenants set forth herein, **THE PARTIES AGREE** as follows:

ARTICLE I

DEFINITIONS AND INTERPRETATION

Master Definitions Supplement. All terms and expressions used in this Agreement shall have the same meaning as those contained in the Master Definitions Supplement to the ISO Tariff.

Rules of Interpretation. The following rules of interpretation and conventions shall apply to this Agreement:

- (a) if there is any inconsistency between this Agreement and the ISO Tariff, the ISO Tariff will prevail to the extent of the inconsistency;
- (b) the singular shall include the plural and vice versa;
- (c) the masculine shall include the feminine and neutral and vice versa;
- (d) "includes" or "including" shall mean "including without limitation";
- (e) references to a Section, Article or Schedule shall mean a Section, Article or a Schedule of this Agreement, as the case may be, unless the context otherwise requires;
- (f) a reference to a given agreement 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;
- (g) unless the context otherwise requires, references to any law shall be deemed references to such law as it may be amended, replaced or restated from time to time;
- (h) unless the context otherwise requires, any reference to a "person" includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization or other entity, in each case whether or not having separate legal personality;
- (i) unless the context otherwise requires, any reference to a Party includes a reference to its permitted successors and assigns;
- (j) any reference to a day, week, month or year is to a calendar day, week, month or year; and
- (k) the captions and headings in this Agreement are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Agreement.

ARTICLE II

ACKNOWLEDGEMENTS OF PARTICIPATING GENERATOR AND ISO

- 2.1 ISO Responsibility.** The Parties acknowledge that the ISO is responsible for the efficient use and reliable operation of the ISO Controlled Grid consistent with achievement of planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating Council and the North American Electric Reliability Council and further acknowledges that the ISO may not be able to satisfy fully these responsibilities if the Participating Generator fails to fully comply with all of its obligations under this Agreement and the ISO Tariff.
- 2.2 Scope of Application to Parties.** The Participating Generator and ISO acknowledge that all Generators, except those specified in Section 2.2.1 of this Agreement, wishing to schedule Energy and to submit Adjustment Bids, Supplemental Energy bids and bids for Ancillary Services to the ISO through a Scheduling Coordinator must sign this Agreement in accordance with Section 5 of the ISO Tariff.
- 2.2.1 Exemption for Certain Generators.** The Generator with an existing power purchase agreement with a UDC is not required to sign a Participating Generator Agreement if: (a) the Generator sells all of its Energy (excluding any Energy consumed by auxiliary load equipment electrically connected to that Generator at the same point) and Ancillary Services to the UDC; (b) the Generator sells any Energy through "over the fence" arrangements as authorized under Section 218(b) of the California Public Utilities Code; or (c) the Generator employs landfill gas technology for the generation of electricity as authorized under 218(c) of the California Public Utilities Code. With respect to subsections (a) and (b), an existing power purchase agreement shall mean an agreement which has been entered into and is effective as of December 20, 1995. With respect to subsection (c), an existing power purchase agreement shall mean an agreement which has been entered into and is effective as of December 31, 1996.

ARTICLE III

TERM AND TERMINATION

- 3.1 Effective Date.** This Agreement shall be effective as of the later of the date it is executed by the Parties or the date accepted for filing and made effective by FERC, and shall remain in full force and effect until terminated pursuant to Section 3.2 of this Agreement.
- 3.2 Termination**
- 3.2.1 Termination by ISO.** Subject to Section 5.2, the ISO may terminate this Agreement by giving written notice of termination in the event that the Participating Generator commits any material default under this Agreement and/or the ISO Tariff which, if capable of being remedied, is not remedied within thirty (30) days after the ISO has given, to the Participating Generator, written notice of the default, unless excused by reason of Uncontrollable Forces in accordance with Article

X of this Agreement. With respect to any notice of termination given pursuant to this Section, the ISO must file a timely notice of termination with FERC. The filing of the notice of termination by the ISO will be considered timely if: (1) the request to file a notice of termination is made after the preconditions for termination have been met, and (2) the ISO files the notice of termination within 30 days of receipt of such request. This Agreement shall terminate upon acceptance by FERC of such a notice of termination.

3.2.2 Termination by Participating Generator. In the event that the Participating Generator no longer wishes to schedule Energy or provide Ancillary Services through a Scheduling Coordinator over the ISO Controlled Grid, it may terminate this Agreement, on giving the ISO ninety (90) days written notice, provided, however, that in accordance with Section 4.1.3, the Participating Generator may modify Schedule 1 to eliminate Generating Units which it no longer owns or no longer has contractual entitlement to and such modification shall be effective upon receipt by the ISO. With respect to any notice of termination given pursuant to this Section, the ISO must file a timely notice of termination with FERC. The filing of the notice of termination by the ISO will be considered timely if: (1) the request to file a notice of termination is made after the preconditions for termination have been met, and (2) the ISO files the notice of termination within 30 days of receipt of such request. This Agreement shall terminate upon acceptance by FERC of such a notice of termination.

ARTICLE IV

GENERAL TERMS AND CONDITIONS

4.1 Generating Units

4.1.1 Identification of Generating Units. The Participating Generator has identified the Generating Units that it owns, operates or has a contractual entitlement to in Schedule 1, as required by Section 4.6.4 of the ISO Tariff.

4.1.2 Technical Characteristics. The Participating Generator has provided to the ISO in Schedule 1 the required information regarding the capacity and operating characteristics of each of the Generating Units listed in that schedule. Pursuant to Section 8.10.1 of the ISO Tariff, the ISO may verify, inspect and test the capacity and operating characteristics provided in Schedule 1.

4.1.3 Notification of Changes. Sixty (60) days prior to changing any technical information in Schedule 1, the Participating Generator shall notify the ISO of the proposed changes. Pursuant to Section 8.10.1 of the ISO Tariff, the ISO may verify, inspect and test the capacity and operating characteristics provided in the revised Schedule 1. The ISO shall post on the ISO Home Page a schedule showing, for at least one year in advance: (i) the proposed dates on which the ISO's Master File will be updated, which dates shall occur at least every three months; (ii) the dates on which the information contained in the revised Master File will become effective; and (iii) the deadlines by which changed technical information must be submitted to the ISO in order to be tested and included in the next scheduled update of the ISO's Master File. 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 and is tested by the deadline. Subject to such notification this Agreement shall not apply to any generating unit identified in Schedule 1 which the Participating Generator no longer owns or no longer has contractual entitlement to.

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. This Agreement shall be subject to the ISO Tariff which shall be deemed to be incorporated herein.

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. Except as provided in Section 4.3.3, the Participating Generator shall not use a Scheduling Coordinator to submit a bid 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.

4.3.3 Initial Exemption. Not later than November 1, 1998, the ISO shall fully implement its certification process in accordance with Sections 8.4 and 8.10 of the ISO Tariff. Until full implementation of the certification process and notification of the Participating Generator and its Scheduling Coordinator of the completion of such process, the non-certified Scheduling Coordinator on behalf of a Participating Generator may submit a bid for the provision of an Ancillary Service or submit a schedule for the self provision of an Ancillary Service. Upon timely notification by the ISO, the Participating Generator must complete the certification process prior to November 1, 1998 to continue its participation in accordance with Section 4.6.7.3 of this Agreement.

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.

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 the ISO Tariff, 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.

ARTICLE VI

COSTS

- 6.1 Operating and Maintenance Costs.** The Participating Generator shall be responsible for all its costs incurred in connection with operating and maintaining the Generating Units identified in Schedule 1 for the purpose of meeting its obligations under this Agreement.

ARTICLE VII

DISPUTE RESOLUTION

- 7.1 Dispute Resolution.** The Parties shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. In the event any dispute is not settled, the Parties shall adhere to the ISO ADR Procedures set forth in Section 13 of the ISO Tariff, which is incorporated by reference, except that any reference in Section 13 of the ISO Tariff to Market Participants shall be read as a reference to the Participating Generator and references to the ISO Tariff shall be read as references to this Agreement.

ARTICLE VIII

REPRESENTATIONS AND WARRANTIES

- 8.1 Representation and Warranties.** Each Party represents and warrants that the execution, delivery and performance of this Agreement by it has been duly authorized by all necessary corporate and/or governmental actions, to the extent authorized by law.
- 8.2 Necessary Approvals.** The Participating Generator represents that all necessary leases, approvals, permits, licenses, easements, rights of way or access to install, own and/or operate its Generating Units have been or will be obtained by the Participating Generator prior to the effective date of this Agreement.

ARTICLE IX

LIABILITY

- 9.1 Liability.** The provisions of Section 14 of the ISO Tariff will apply to liability arising under this Agreement, except that all references in Section 14 of the ISO Tariff to Market Participants shall be read as references to the Participating Generator and references to the ISO Tariff shall be read as references to this Agreement.

ARTICLE X

UNCONTROLLABLE FORCES

- 10.1 Uncontrollable Forces Tariff Provisions.** Section 14 of the ISO Tariff shall be incorporated by reference into this Agreement except that all references in Section 14 of the ISO Tariff to Market Participants shall be read as a reference to the Participating Generator and references to the ISO Tariff shall be read as references to this Agreement.

ARTICLE XI

MISCELLANEOUS

- 11.1 Assignments.** Either Party may assign or transfer any or all of its rights and/or obligations under this Agreement with the other Party's prior written consent in accordance with Section 22.2 of the ISO Tariff. Such consent shall not be unreasonably withheld. Any such transfer or assignment shall be conditioned upon the successor in interest accepting the rights and/or obligations under this Agreement as if said successor in interest was an original Party to this Agreement.
- 11.2 Notices.** Any notice, demand or request which may be given to or made upon either Party regarding this Agreement shall be made in accordance with Section 22.4 of the ISO Tariff. A Party must update the information in Schedule 3 of this Agreement as information changes. Such changes shall not constitute an amendment to this Agreement.
- 11.3 Waivers.** Any waivers at any time by either 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.
- 11.4 Governing Law and Forum.** This Agreement shall be deemed to be a contract made under, and for all purposes shall be governed by and construed in accordance with, the laws of the State of California, except its conflict of law provisions. The Parties irrevocably consents that any legal action or proceeding arising under or relating to this Agreement to which the ISO ADR Procedures

do not apply, shall be brought in any of the following forums, as appropriate: any court of the State of California, any federal court of the United States of America located in the State of California, or, where subject to its jurisdiction, before the Federal Energy Regulatory Commission.

- 11.5 Consistency with Federal Laws and Regulations.** This Agreement shall incorporate by reference Section 22.9 of the ISO Tariff as if the references to the ISO Tariff were referring to this Agreement.
- 11.6 Merger.** This Agreement constitutes the complete and final agreement of the Parties with respect to the subject matter hereto and supersedes all prior agreements, whether written or oral, with respect to such subject matter.
- 11.7 Severability.** If any term, covenant, or condition of this Agreement or the application or effect of any such term, covenant, or condition is held invalid as to any person, entity, or circumstance, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in force and effect to the maximum extent permitted by law, and all other terms, covenants, and conditions of this Agreement and their application shall not be affected thereby, but shall remain in force and effect and the Parties shall be relieved of their obligations only to the extent necessary to eliminate such regulatory or other determination unless a court or governmental agency of competent jurisdiction holds that such provisions are not separable from all other provisions of this Agreement.
- 11.8 Section Headings.** Section headings provided in this Agreement are for ease of reading and are not meant to interpret the text in each Section.
- 11.9 Amendments.** This Agreement and the Schedules attached hereto may be amended from time to time by the mutual agreement of the Parties in writing. Amendments that require FERC approval shall not take effect until FERC has accepted such amendments for filing and made them effective. If the amendment does not require FERC approval, the amendment will be filed with FERC for information.
- 11.10 Counterparts.** This Agreement may be executed in one or more counterparts at different times, each of which shall be regarded as an original and all of which, taken together, shall constitute one and the same Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed on behalf of each by and through their authorized representatives as of the date hereinabove written.

California Independent System Operator Corporation

By: _____

Name: _____

Title: _____

Date: _____

[NAME OF PARTICIPATING GENERATOR]

By: _____

Name: _____

Title: _____

Date: _____

[The following page is a placeholder for Schedule 1, Section 1.]

The following page is a placeholder for Schedule 1, Section 2.

SCHEDULE 2

ISO IMPOSED PENALTIES AND SANCTIONS

Section 4.6.1

TO BE INSERTED UPON FERC APPROVAL

SCHEDULE 3

NOTICES

Section 10.2

Participating Generator

Name of Primary

Representative: _____

Title: _____

Company: _____

Address: _____

City/State/Zip Code: _____

Email Address: _____

Phone: _____

Fax No: _____

Name of Alternative

Representative: _____

Title: _____

Company: _____

Address: _____

City/State/Zip Code: _____

Email Address: _____

Phone: _____

Fax No: _____

ISO

Name of Primary

Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email Address: _____

Phone: _____

Fax No: _____

Name of Alternative

Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email Address: _____

Phone: _____

Fax No: _____

ISO TARIFF APPENDIX B.3
Qualifying Facility Participating Generator Agreement

CALIFORNIA INDEPENDENT SYSTEM OPERATOR

AND

[name of QF PARTICIPATING GENERATOR]

QUALIFYING FACILITY PARTICIPATING GENERATOR AGREEMENT

QUALIFYING FACILITY PARTICIPATING GENERATOR AGREEMENT (QF PGA)

THIS AGREEMENT is dated this ____ day of _____, ____ and is entered into, by and between:

(3) **[Full Legal Name]**, having its registered and principal place of business located at **[Address]** (the "Participating Generator");

and

(4) **California Independent System Operator Corporation**, a California nonprofit public benefit corporation having a principal executive office located at such place in the State of California as the ISO Governing Board may from time to time designate, initially 151 Blue Ravine Road, Folsom, California 95630 (the "ISO").

The Participating Generator and the ISO are hereinafter referred to as the "Parties".

Whereas:

- A.** The ISO Tariff provides that the ISO shall not schedule Energy or Ancillary Services generated by any Generating Unit interconnected to the ISO Controlled Grid, or to the Distribution System of a Participating TO or of a UDC or MSS Operator otherwise than through a Scheduling Coordinator.
- B.** The ISO Tariff further provides that the ISO shall not be obliged to accept Schedules or Adjustment Bids or bids for Ancillary Services relating to Generation from any Generating Unit interconnected to the ISO Controlled Grid unless the relevant Generator undertakes in writing to the ISO to comply with all applicable provisions of the ISO Tariff.
- C.** The Participating Generator wishes to be able to Schedule Energy and to submit Adjustment Bids, Supplemental Energy bids and bids for Ancillary Services from a Qualifying Facility Net Scheduled QF to the ISO through a Scheduling Coordinator and, therefore, wishes to undertake to the ISO that it will comply with the applicable provisions of the ISO Tariff, except as otherwise specified in this Agreement.
- D.** It is the intent of the Parties that this Agreement will harmonize the special operational characteristics of the Participating Generator's Qualifying Facility with the ISO's Grid operation function. Nothing in this Agreement is intended to limit or restrict the rights of the Participating Generator under Section 4.6.3.2 of the ISO Tariff.
- E.** The Parties are entering into this Agreement in order to establish the terms and conditions on which the ISO and the Participating Generator will discharge their respective duties and responsibilities under the ISO Tariff.

NOW THEREFORE, in consideration of the mutual covenants set forth herein, **THE PARTIES AGREE** as follows:

ARTICLE I

DEFINITIONS AND INTERPRETATION

Master Definitions Supplement. Unless defined in this Agreement, all capitalized terms and expressions used in this Agreement shall have the same meaning as those contained in the Master Definitions Supplement to the ISO Tariff.

Special Definitions for this Agreement. In this Agreement, the following words and expressions shall have the meanings set forth below:

"Existing QF Contract" means an agreement for the sale of capacity, Energy, and/or Ancillary Services by the Participating Generator to an electric utility from a Qualifying Facility that became effective on or prior to December 20, 1995 or, in the case of a Participating Generator employing landfill gas technology, on or prior to December 31, 1996.

"Net Scheduled QF" means the Qualifying Facility identified in Schedule 1 of this Agreement operated as a single unit such that the Energy scheduled with the ISO is the net value of the aggregate electrical net output of the Qualifying Facility and the Self-provided Load.

"Point of Demarcation" means the point: (1) where the Participating Generator's electrical conductors contact an electric utility system or the ISO Controlled Grid; or (2) if dedicated utility distribution facilities are employed, where the dedicated facilities contact the electric utility system or the ISO Controlled Grid.

"Qualifying Facility" (QF) means 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).

"Self-provided Load" means the portion of Load that is served by the Net Scheduled QF listed in Schedule 1 consistent with Section 218(b) of the California Public Utilities Code.

Rules of Interpretation. The following rules of interpretation and conventions shall apply to this Agreement:

- (a) if there is any inconsistency between this Agreement and the ISO Tariff, the ISO Tariff will prevail to the extent of the inconsistency, except as expressly provided otherwise in this Agreement;
- (b) the singular shall include the plural and vice versa;
- (c) the masculine shall include the feminine and neutral and vice versa;
- (d) "includes" or "including" shall mean "including without limitation";
- (e) references to a Section, Article or Schedule shall mean a Section, Article or a Schedule of this Agreement, as the case may be, unless the context otherwise requires;
- (f) a reference to a given agreement 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;
- (g) unless the context otherwise requires, references to any law shall be deemed references to such law as it may be amended, replaced or restated from time to time;
- (h) unless the context otherwise requires, any reference to a "person" includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization or other entity, in each case whether or not having separate legal personality;
- (i) unless the context otherwise requires, any reference to a Party includes a reference to its permitted successors and assigns;
- (j) any reference to a day, week, month or year is to a calendar day, week, month or year; and
- (l) the captions and headings in this Agreement are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Agreement.

ARTICLE II

ACKNOWLEDGEMENTS OF PARTICIPATING GENERATOR AND ISO

2.1 ISO Responsibility. The Parties acknowledge that the ISO is responsible for the efficient use and reliable operation of the ISO Controlled Grid consistent with achievement of planning and operating reserve criteria no less stringent than those established by the Western Electricity Coordinating Council and the North American Electric Reliability Council and further acknowledges that the ISO

may not be able to satisfy fully these responsibilities if the Participating Generator fails to fully comply with all of its obligations under this Agreement.

2.2 Scope of Application to Parties. The Participating Generator and ISO acknowledge that all Qualifying Facility Generators, except those specified in Section 2.2.1 of this Agreement, wishing to schedule Energy and to submit Adjustment Bids, Supplemental Energy bids and bids for Ancillary Services to the ISO through a Scheduling Coordinator shall first execute this Agreement or the standard Participating Generator Agreement applicable to non-QF Generators. The Parties acknowledge that execution of this Agreement by the Participating Generator satisfies the requirement of a written agreement as set forth in Section 4.6 of the ISO Tariff.

2.2.1 Exemption for Certain Generators. The Generator with a Net Scheduled QF with an existing power purchase agreement with a UDC is not required to sign a QF Participating Generator Agreement if: (a) the Generator sells all of its Energy (excluding any Energy consumed by auxiliary load equipment electrically connected to that Generator at the same point) and Ancillary Services to the UDC; (b) the Generator sells any Energy through "over the fence" arrangements as authorized under Section 218(b) of the California Public Utilities Code; or (c) the Generator employs landfill gas technology for the generation of electricity as authorized under 218(c) of the California Public Utilities Code. With respect to subsections (a) and (b), an existing power purchase agreement shall mean an agreement which has been entered into and is effective as of December 20, 1995. With respect to subsection (c), an existing power purchase agreement shall mean an agreement which has been entered into and is effective as of December 31, 1996.

ARTICLE III

TERM AND TERMINATION

3.1 Effective Date. This Agreement shall remain in full force and effect until terminated pursuant to Section 3.2 of this Agreement and shall be effective as of the later of: (1) the date the Agreement is executed by the Parties; or (2) where the Participating Generator is a party to an existing Participating Generator Agreement, the date upon which termination of the existing Participating Generator Agreement is accepted for filing and made effective by FERC; or (3) where the Participating Generator is a party to an existing Participating Generator Agreement and this Agreement is required to be filed with FERC for acceptance, the later of the date upon which termination of the existing Participating Generator Agreement is accepted for filing and made effective by FERC, or the date this Agreement is accepted for filing and made effective by FERC.

3.2 Termination

3.2.1 Termination by ISO. Subject to Section 5.2, the ISO may terminate this Agreement by giving written notice of termination in the event that the Participating Generator commits any material default under this Agreement and/or the ISO Tariff which, if capable of being remedied, is not remedied within thirty (30) days after the ISO has given, to the Participating Generator, written notice of the default, unless excused by reason of Uncontrollable Forces in accordance with Article X of this Agreement. With respect to any notice of termination given pursuant to this Section, the ISO must file a timely notice of termination with FERC. The filing of the notice of termination by the

ISO will be considered timely if: (1) the request to file a notice of termination is made after the preconditions for termination have been met, and (2) the ISO files the notice of termination within 30 days after receipt of such request. This Agreement shall terminate upon acceptance by FERC of such a notice of termination.

3.2.2 Termination by Participating Generator. In the event that the Participating Generator no longer wishes to schedule Energy or provide Ancillary Services through a Scheduling Coordinator over the ISO Controlled Grid, it may terminate this Agreement, on giving the ISO ninety (90) days written notice, provided, however, that in accordance with Section 4.1.3, the Participating Generator may modify Schedule 1 to eliminate generating resources which it no longer owns or no longer has contractual entitlement to and such modification shall be effective upon receipt by the ISO. With respect to any notice of termination given pursuant to this Section, the ISO must file a timely notice of termination with FERC. The filing of the notice of termination by the ISO will be considered timely if: (1) the request to file a notice of termination is made after the preconditions for termination have been met, and (2) the ISO files the notice of termination within 30 days of receipt of such request. This Agreement shall terminate upon acceptance by FERC of such a notice of termination.

ARTICLE IV

GENERAL TERMS AND CONDITIONS

4.1 Net Scheduled QFs

4.1.1 Identification of Net Scheduled QF. The Participating Generator has identified the Net Scheduled QF that it owns, operates or has a contractual entitlement to, in Schedule 1, as required by Section 4.6.4 of the ISO Tariff.

4.1.2 Technical Characteristics. The Participating Generator shall provide to the ISO the required information regarding operating contacts, rated capacity, and operating characteristics of the Net Scheduled QF. Pursuant to Section 8.10.1 of the ISO Tariff, and the Existing QF Contract, if any, associated with that Net Scheduled QF, the ISO may verify, inspect and test the capacity and operating characteristics of the Net Scheduled QF. The performance of such inspection or test shall be conducted at a time mutually agreed upon by the Parties, which agreement shall not unreasonably be withheld.

4.1.3 Notification of Changes. Sixty (60) days prior to changing any technical information in Schedule 1, the Participating Generator shall notify the ISO of the proposed changes. Pursuant to Section 8.10.1 of the ISO Tariff, the ISO may verify, inspect and test the capacity and operating characteristics; provided that the performance of such inspection or test is conducted at a time mutually agreed upon by the Parties, which agreement shall not unreasonably be withheld. The ISO shall post on the ISO Home Page a schedule showing, for at least one year in advance: (i) the proposed dates on which the ISO's Master File will be updated, which dates shall occur at least every three months; (ii) the dates on which the information contained in the revised Master File will become effective; and (iii) the deadlines by which changed technical information must be submitted to the ISO in order to be tested and included in the next scheduled update of the ISO's Master File.

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.

ARTICLE VI

COSTS

- 6.1 Operating and Maintenance Costs.** The Participating Generator shall be responsible for all its costs incurred in connection with operating and maintaining the Net Scheduled QF identified in Schedule 1 for the purpose of meeting its obligations under this Agreement.

ARTICLE VII

DISPUTE RESOLUTION

- 7.1 Dispute Resolution.** The Parties shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. In the event any dispute is not settled, the Parties shall adhere to the ISO ADR Procedures set forth in Section 13 of the ISO Tariff, which is incorporated by reference, except that any reference in Section 13 of the ISO Tariff to Market Participants shall be read as a reference to the Participating Generator and references to the ISO Tariff shall be read as references to this Agreement.

ARTICLE VIII

REPRESENTATIONS AND WARRANTIES

- 8.1 Representation and Warranties.** Each Party represents and warrants that the execution, delivery and performance of this Agreement by it has been duly authorized by all necessary corporate and/or governmental actions, to the extent authorized by law.
- 8.2 Necessary Approvals.** The Participating Generator represents that all necessary leases, approvals, permits, licenses, easements, rights of way or access to install, own and/or operate its Net Scheduled QF have been or will be obtained by the Participating Generator prior to the effective date of this Agreement.
- 8.3 Specific Warranty.** The Participating Generator represents and warrants that: (1) the Net Scheduled QF listed in Schedule 1 is a Qualifying Facility or is operated as an integral part of a Qualifying Facility and (2) the Self-provided Load of the Participating Generator that is served by the Net Scheduling QF either has contracted for and continues through the term of this Agreement to have secured standby service from a UDC or MSS Operator under terms approved by the local regulatory authority or the Federal Energy Regulatory Commission, as applicable, or that the Self-

provided Load shall be curtailed concurrently with any outage of the generation serving that Self-provided Load in an amount sufficient to cover that outage.

ARTICLE IX

LIABILITY

- 9.1 Liability.** The provisions of Section 14 of the ISO Tariff will apply to liability arising under this Agreement, except that all references in Section 14 of the ISO Tariff to Market Participants shall be read as references to the Participating Generator and references to the ISO Tariff shall be read as references to this Agreement.

ARTICLE X

UNCONTROLLABLE FORCES

- 10.1 Uncontrollable Forces Tariff Provisions.** Section 14 of the ISO Tariff shall be incorporated by reference into this Agreement except that all references in Section 14 of the ISO Tariff to Market Participants shall be read as a reference to the Participating Generator and references to the ISO Tariff shall be read as references to this Agreement.

ARTICLE XI

MISCELLANEOUS

- 11.1 Assignments.** Either Party may assign or transfer any or all of its rights and/or obligations under this Agreement with the other Party's prior written consent in accordance with Section 22.2 of the ISO Tariff. Such consent shall not be unreasonably withheld. Any such transfer or assignment shall be conditioned upon the successor in interest accepting the rights and/or obligations under this Agreement as if said successor in interest was an original Party to this Agreement.
- 11.2 Notices.** Any notice, demand or request which may be given to or made upon either Party regarding this Agreement shall be made in accordance with Section 22.4 of the ISO Tariff. A Party must update the information in Schedule 3 of this Agreement as information changes. Such changes shall not constitute an amendment to this Agreement.

- 11.3 Waivers.** Any waivers at any time by either 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.
- 11.4 Governing Law and Forum.** This Agreement shall be deemed to be a contract made under, and for all purposes shall be governed by and construed in accordance with, the laws of the State of California, except its conflict of law provisions. The Parties irrevocably consent that any legal action or proceeding arising under or relating to this Agreement to which the ISO ADR Procedures do not apply, shall be brought in any of the following forums, as appropriate: any court of the State of California, any federal court of the United States of America located in the State of California, or, where subject to its jurisdiction, before the Federal Energy Regulatory Commission.
- 11.5 Consistency with Federal Laws and Regulations.** This Agreement shall incorporate by reference Section 22.9 of the ISO Tariff as if the references to the ISO Tariff were referring to this Agreement.
- 11.6 Merger.** This Agreement constitutes the complete and final agreement of the Parties with respect to the subject matter hereto and supersedes all prior agreements, whether written or oral, with respect to such subject matter.
- 11.7 Severability.** If any term, covenant, or condition of this Agreement or the application or effect of any such term, covenant, or condition is held invalid as to any person, entity, or circumstance, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in force and effect to the maximum extent permitted by law, and all other terms, covenants, and conditions of this Agreement and their application shall not be affected thereby, but shall remain in force and effect and the Parties shall be relieved of their obligations only to the extent necessary to eliminate such regulatory or other determination unless a court or governmental agency of competent jurisdiction holds that such provisions are not separable from all other provisions of this Agreement.
- 11.8 Section Headings.** Section headings provided in this Agreement are for ease of reading and are not meant to interpret the text in each Section.
- 11.9 Amendments.** This Agreement and the Schedules attached hereto may be amended from time to time by the mutual agreement of the Parties in writing. Amendments that require FERC approval shall not take effect until FERC has accepted such amendments for filing and made them effective. If the amendment does not require FERC approval, the amendment will be filed with FERC for information.
- 11.10 Counterparts.** This Agreement may be executed in one or more counterparts at different times, each of which shall be regarded as an original and all of which, taken together, shall constitute one and the same Agreement.
- 11.11 Rights Reserved.** Execution of this Agreement does not deprive the Participating Generator of any unexpressed legal right, either under law or under an existing power purchase agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed on behalf of each by and through their authorized representatives as of the date hereinabove written.

California Independent System Operator Corporation

By: _____

Name: _____

Title: _____

Date: _____

[NAME OF PARTICIPATING GENERATOR]

By: _____

Name: _____

Title: _____

Date: _____

The following page is a placeholder for Schedule 1, Section 1.

SCHEDULE 2

ISO IMPOSED PENALTIES AND SANCTIONS

[Section 4.6.1]

TO BE INSERTED UPON FERC APPROVAL

SCHEDULE 3

NOTICES
(Section 11.2)

Participating Generator

Name of Primary

Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email Address: _____

Phone: _____

Fax No: _____

Name of Alternative

Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email Address: _____

Phone: _____

Fax No: _____

ISO

Name of Primary

Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email Address: _____

Phone: _____

Fax No: _____

Name of Alternative

Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email Address: _____

Phone: _____

Fax No: _____

ISO TARIFF APPENDIX B.4
Participating Load Agreement

CALIFORNIA INDEPENDENT SYSTEM OPERATOR

AND

[PARTICIPATING LOAD]

PARTICIPATING LOAD AGREEMENT

PARTICIPATING LOAD AGREEMENT (PLA)

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

(1) **[Full legal name]**, having its registered and principal place of business located at [legal address] (the "Participating Load");

and

(2) **California Independent System Operator Corporation**, a California nonprofit public benefit corporation having a principal executive office located at such place in the State of California as the ISO Governing Board may from time to time designate, initially 151 Blue Ravine Road, Folsom, California 95630 (the "ISO").

The Participating Load and the ISO are hereinafter referred to as the "Parties".

Whereas:

- A.** The ISO Tariff provides that the ISO shall not schedule Ancillary Services from a Load interconnected to the ISO Controlled Grid, or to the Distribution System of a Participating TO or of a UDC otherwise than through a Scheduling Coordinator.
- B.** The ISO Tariff further provides that Curtailable Demand or Dispatchable Load services shall be provided by Participating Loads.
- C.** The Participating Load desires to provide Curtailable Demand or Dispatchable Load services, intends to submit Adjustment Bids, Supplemental Energy bids or Ancillary Services bids, or self-provided schedules to the ISO through a Scheduling Coordinator and, therefore, represents to the ISO that it will comply with the applicable provisions of the ISO Tariff.
- D.** The Parties are entering into this Agreement in order to establish the terms and conditions on which the ISO and the Participating Load will discharge their respective duties and responsibilities under the ISO Tariff.

NOW THEREFORE, in consideration of the mutual covenants set forth herein, **THE PARTIES AGREE** as follows:

ARTICLE I

DEFINITIONS AND INTERPRETATION

- 1.1 Master Definitions Supplement.** All terms and expressions used in this Agreement shall have the same meaning as those contained in the Master Definitions Supplement to the ISO Tariff.
- 1.2 Rules of Interpretation.** The following rules of interpretation and conventions shall apply to this Agreement:
- (a) if there is any inconsistency between this Agreement and the ISO Tariff, the ISO Tariff will prevail to the extent of the inconsistency;
 - (b) the singular shall include the plural and vice versa;
 - (c) the masculine shall include the feminine and neutral and vice versa;
 - (d) "includes" or "including" shall mean "including without limitation";
 - (e) references to a Section, Article or Schedule shall mean a Section, Article or a Schedule of this Agreement, as the case may be, unless the context otherwise requires;
 - (f) a reference to a given agreement 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;
 - (g) unless the context otherwise requires, references to any law shall be deemed references to such law as it may be amended, replaced or restated from time to time;
 - (h) unless the context otherwise requires, any reference to a "person" includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization or other entity, in each case whether or not having separate legal personality;
 - (i) unless the context otherwise requires, any reference to a Party includes a reference to its permitted successors and assigns;
 - (j) any reference to a day, week, month or year is to a calendar day, week, month or year; and
 - (k) the captions and headings in this Agreement are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Agreement.

ARTICLE II

ACKNOWLEDGEMENTS OF PARTICIPATING LOAD AND ISO

- 2.1 ISO Responsibility.** The Parties acknowledge that the ISO is responsible for the efficient use and reliable operation of the ISO Controlled Grid consistent with achievement of planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating Council and the North American Electric Reliability Council and further acknowledge that the ISO may not be able to satisfy fully these responsibilities if the Participating Load fails to fully comply with all of its obligations under this Agreement and the ISO Tariff.
- 2.2 Scope of Application to Parties.** The Participating Load and ISO acknowledge that all Loads which desire to submit Adjustment Bids, Supplemental Energy bids, or Ancillary Services bids or self-provided schedules to the ISO through a Scheduling Coordinator must be included in Schedule 1 to this Agreement. The Participating Load warrants that it owns, operates, or has sufficient contractual entitlement to provide Curtailable Demand and Dispatchable Load services from such Loads in accordance with the ISO Tariff.

ARTICLE III

TERM AND TERMINATION

- 3.1 Effective Date.** This Agreement shall be effective as of the later of the date it is executed by the Parties or the date accepted for filing and made effective by FERC, and shall remain in full force and effect until terminated pursuant to Section 3.2 of this Agreement.
- 3.2 Termination**
- 3.2.1 Termination by ISO.** Subject to Section 5.2, the ISO may terminate this Agreement by giving written notice of termination in the event that the Participating Load commits any material default under this Agreement and/or the ISO Tariff which, if capable of being remedied, is not remedied within thirty (30) days after the ISO has given, to the Participating Load, written notice of the default, unless excused by reason of Uncontrollable Forces in accordance with Article X of this Agreement. With respect to any notice of termination given pursuant to this Section, the ISO must file a timely notice of termination with FERC. The filing of the notice of termination by the ISO will be considered timely if: (1) the request to file a notice of termination is made after the preconditions for termination have been met, and (2) the ISO files the notice of termination within thirty (30) days of receipt of such request. This Agreement shall terminate upon acceptance by FERC of such a notice of termination.
- 3.2.2 Termination by Participating Load.** In the event that the Participating Load no longer wishes to submit Adjustment Bids, Supplemental Energy bids, or Ancillary Service bids or self-provided schedules over the ISO Controlled Grid, it may terminate this Agreement, on giving the ISO ninety (90) days written notice, provided, however, that in accordance with Section 4.4, the Participating Load may modify Schedule 1 to eliminate Load which it no longer provides for and such

modification shall be effective upon receipt by the ISO. With respect to any notice of termination given pursuant to this Section, the ISO must file a timely notice of termination with FERC. The filing of the notice of termination by the ISO will be considered timely if: (1) the request to file a notice of termination is made after the preconditions for termination have been met, and (2) the ISO files the notice of termination within thirty (30) days of receipt of such request. This Agreement shall terminate upon acceptance by FERC of such a notice of termination.

ARTICLE IV

GENERAL TERMS AND CONDITIONS

4.1 Technical Characteristics.

4.1.1 Curtailable Demand. As required by Section 8.4 of the ISO Tariff, the Participating Load shall provide the ISO with all technical and operational information requested in Schedule 1 for each Curtailable Demand that it owns, operates, or has a contractual entitlement to. For those Loads designated by the Participating Load as providing Curtailable Demand, Schedule 1 requires the Participating Load to indicate in Schedule 1 whether the Load can be scheduled or bid as Non-Spinning Reserve or Replacement Reserve. Pursuant to Section 8.10.1 of the ISO Tariff, the ISO may verify, inspect and test the capacity and operating characteristics provided in Schedule 1 for Curtailable Demands.

4.1.2 Dispatchable Load. The Participating Load shall provide the ISO that information required in Schedule 1 which is relevant to the Dispatchable Load that it owns, operates, or has a contractual entitlement to for the provision of Adjustment Bids.

4.2 Metering and Communication.

4.2.1 Curtailable Demand. Pursuant to Sections 8.4.4 and 8.4.6 of the ISO Tariff, Curtailable Demand that is scheduled or bid as Non-Spinning Reserve or Replacement Reserve is required to comply with the ISO's communication and metering requirements.

4.2.2 Dispatchable Load. The Participating Load shall schedule Dispatchable Load pursuant to Section 30.2.1 of the ISO Tariff. Dispatchable Load shall comply with the ISO's communication and metering requirements.

4.3 UDC Interruptible Load Programs. Due to the ISO's reliance on interruptible Loads to relieve System Emergencies and its contractual relationship with each UDC, the ISO will not accept, and the Participating Load shall not submit Adjustment Bids, Supplemental Energy bids, or Ancillary Services bids or self-provided Ancillary Service Schedules from interruptible Loads which are subject to curtailment criteria established under existing retail tariffs, except under such conditions as may be specified in the ISO Tariff.

4.4 Notification of Changes. Sixty (60) days prior to changing any technical information in Schedule 1, the Participating Load shall notify the ISO of the proposed change(s). Pursuant to Section 8.10.1 of the ISO Tariff, the ISO may verify, inspect and test the capacity and operating characteristics provided in the revised Schedule 1. The ISO shall post on the ISO Home Page a schedule

showing, for at least one year in advance: (i) the proposed dates on which the ISO's Master File will be updated; (ii) the dates on which the information contained in the revised Master File will become effective; and (iii) the deadlines by which changed technical information must be submitted to the ISO in order to be tested and included in the next scheduled update of the ISO's Master File. Unless the Load fails to test at the values in the proposed change(s), the Participating Load's proposed change(s) will become effective upon the effective date for the next scheduled update of the Master File, provided that the Participating Load submits the changed information by the applicable deadline and is tested by the deadline. Subject to such notification this Agreement shall not apply to any Loads identified in Schedule 1 which the Participating Load no longer owns or no longer has a contractual entitlement to.

4.5 Agreement Subject to ISO Tariff. The Parties will comply with all applicable provisions of the ISO Tariff, including Sections 7.4, 8 and 10. This Agreement shall be subject to the ISO Tariff, which shall be deemed to be incorporated herein.

4.6 Obligations Relating to Ancillary Services

4.6.1 Submission of Bids and Self-provided Schedules. When the Scheduling Coordinator on behalf of the Participating Load submits a bid or self-provided schedule for Ancillary Services, the Participating Load will, by the operation of this Section 4.6.1, 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.

4.6.2 Certification. The Participating Load shall not use a Scheduling Coordinator to submit a bid 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 Load is in possession of a current Ancillary Service certificate pursuant to Sections 8.4 and 8.10 of the ISO Tariff.

4.7 Obligations relating to Major Incidents. The Participating Load shall promptly provide such information as the ISO may reasonably require in relation to the ISO's investigations of operating situations or events, or for the ISO's reporting to the authorities such as the FERC, California Public Utilities Commission, Western Systems Coordinating Council, or North American Electric Reliability Council.

ARTICLE V

PENALTIES AND SANCTIONS

5.1 Penalties. If the Participating Load fails to comply with any provisions of this Agreement, the ISO shall be entitled to impose penalties and sanctions on the Participating Load, including the penalties set forth in Section 8.10.2 of the ISO Tariff. 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 this Agreement, with the exception of the provisions relating to ADR, shall be construed as waiving the rights of the Participating Load 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 Load.

- 5.2 Corrective Measures.** If the Participating Load fails to meet or maintain the requirements set forth in this Agreement and/or the ISO Tariff, 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.

ARTICLE VI

COSTS

- 6.1 Operating and Maintenance Costs.** The Participating Load shall be responsible for all its costs incurred in meeting its obligations under this Agreement for the Load identified in Schedule 1.

ARTICLE VII

DISPUTE RESOLUTION

- 7.1 Dispute Resolution.** The Parties shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. In the event any dispute is not settled, the Parties shall adhere to the ISO ADR Procedures set forth in Section 13 of the ISO Tariff, which is incorporated by reference, except that any reference in Section 13 of the ISO Tariff to Market Participants shall be read as a reference to the Participating Load and references to the ISO Tariff shall be read as references to this Agreement.

ARTICLE VIII

REPRESENTATIONS AND WARRANTIES

- 8.1 Representation and Warranties.** Each Party represents and warrants that the execution, delivery and performance of this Agreement by it has been duly authorized by all necessary corporate and/or governmental actions, to the extent authorized by law.
- 8.2 Necessary Approvals.** The Participating Load represents that all necessary leases, approvals, permits, licenses, easements, rights of way or access to install, own and/or operate its Load have been or will be obtained by the Participating Load prior to the effective date of this Agreement.

ARTICLE IX

LIABILITY

- 9.1 Liability.** The provisions of Section 14 of the ISO Tariff will apply to liability arising under this Agreement, except that all references in Section 14 of the ISO Tariff to Market Participants shall be read as references to the Participating Load and references to the ISO Tariff shall be read as references to this Agreement.

ARTICLE X

UNCONTROLLABLE FORCES

- 10.1 Uncontrollable Forces Tariff Provisions.** Section 14 of the ISO Tariff shall be incorporated by reference into this Agreement except that all references in Section 14 of the ISO Tariff to Market Participants shall be read as a reference to the Participating Load and references to the ISO Tariff shall be read as references to this Agreement.

ARTICLE XI

MISCELLANEOUS

- 11.1 Assignments.** Either Party may assign or transfer any or all of its rights and/or obligations under this Agreement with the other Party's prior written consent in accordance with Section 22.2 of the ISO Tariff. Such consent shall not be unreasonably withheld. Any such transfer or assignment shall be conditioned upon the successor in interest accepting the rights and/or obligations under this Agreement as if said successor in interest was an original Party to this Agreement.
- 11.2 Notices.** Any notice, demand, or request which may be given to or made upon either Party regarding this Agreement shall be made in accordance with Section 22.4 of the ISO Tariff. A Party must update the information in Schedule 3 of this Agreement as information changes. Such changes shall not constitute an amendment to this Agreement.
- 11.3 Waivers.** Any waivers at any time by either 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.
- 11.4 Governing Law and Forum.** This Agreement shall be deemed to be a contract made under, and for all purposes shall be governed by and construed in accordance with, the laws of the State of California, except its conflict of law provisions. The Parties irrevocably consent that any legal action

or proceeding arising under or relating to this Agreement to which the ISO ADR Procedures do not apply, shall be brought in any of the following forums, as appropriate: any court of the State of California, any federal court of the United States of America located in the State of California, or, where subject to its jurisdiction, before the Federal Energy Regulatory Commission.

- 11.5 Consistency with Federal Laws and Regulations.** This Agreement shall incorporate by reference Section 22.9 of the ISO Tariff as if the references to the ISO Tariff were referring to this Agreement.
- 11.6 Merger.** This Agreement constitutes the complete and final agreement of the Parties with respect to the subject matter hereto and supersedes all prior agreements, whether written or oral, with respect to such subject matter.
- 11.7 Severability.** If any term, covenant, or condition of this Agreement or the application or effect of any such term, covenant, or condition is held invalid as to any person, entity, or circumstance, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in force and effect to the maximum extent permitted by law, and all other terms, covenants, and conditions of this Agreement and their application shall not be affected thereby, but shall remain in force and effect and the Parties shall be relieved of their obligations only to the extent necessary to eliminate such regulatory or other determination unless a court or governmental agency of competent jurisdiction holds that such provisions are not separable from all other provisions of this Agreement.
- 11.8 Section Headings:** Section headings provided in this Agreement are for ease of reading and are not meant to interpret the text in each Section.
- 11.9 Amendments.** This Agreement and the Schedules attached hereto may be amended from time to time by the mutual agreement of the Parties in writing. Amendments that require FERC approval shall not take effect until FERC has accepted such amendments for filing and made them effective. If the amendment does not require FERC approval, the amendment will be filed with FERC for information. Nothing contained herein shall be construed as affecting in any way the right of the ISO to unilaterally make application to the Federal Energy Regulatory Commission for a change in the rates, terms and conditions under section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder.
- 11.10 Counterparts.** This Agreement may be executed in one or more counterparts at different times, each of which shall be regarded as an original and all of which, taken together, shall constitute one and the same Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed on behalf of each by and through their authorized representatives as of the date herein above written.

California Independent System Operator Corporation

By: _____

Name: _____

Title: _____

Date: _____

Participating Load

By: _____

Name: _____

Title: _____

Date: _____

SCHEDULE 1

Technical Characteristics of Individual or Aggregated Loads Participating under Participating Load Agreement

Name of ALMDS Facility or Individual Load	ISO Resource ID	Present Scheduling Point (i.e. Take Out Point, Load Group, or Demand Zone)	Capacity Available ¹ (MW)	Minimum Operating Level ¹ (MW)	Maximum Operating Level ^{1,2} (MW)	Decremental Ramp Rate ^{1,2} (MW/min)	Ancillary Service Provider (Yes or No)	Participant in UDC Interruptible Program (Yes or No)	Limitations ³ (Yes or No)

¹ Current effective values for purposes of scheduling Energy and bidding to provide Energy and/or Ancillary Services in ISO markets may differ from those set forth in this Schedule 1, depending on the results of ISO performance testing pursuant to Sections 8.10 of the ISO Tariff.

² These values are subject to certification by the ISO in accordance with Section 4.4.6.2 of the Participating Load Agreement.

³ If "Yes," limitations should be specified in the Participating Load's implementation plan.

SCHEDULE 2

ISO IMPOSED PENALTIES AND SANCTIONS

[Section 5.1]

TO BE INSERTED UPON FERC APPROVAL

SCHEDULE 3

NOTICES
(Section 10.2)

Participating Load

Name of Primary

Representative:

Title:

Address:

City/State/Zip Code

Email Address:

Phone:

Fax No:

Name of Alternative

Representative:

Title:

Address:

City/State/Zip Code

Email Address:

Phone:

Fax No:

ISO

Name of Primary

Representative:

Title:

Address:

City/State/Zip Code

Email Address:

Phone:

Fax No:

Name of Alternative

Representative:

Title:

Address:

City/State/Zip Code

Email Address:

Phone:

Fax No:

ISO TARIFF APPENDIX B.5
Dynamic Scheduling Agreement for Scheduling Coordinators

CALIFORNIA INDEPENDENT SYSTEM OPERATOR

AND

[SCHEDULING COORDINATOR]

DYNAMIC SCHEDULING AGREEMENT FOR SCHEDULING COORDINATORS

DYNAMIC SCHEDULING AGREEMENT FOR SCHEDULING COORDINATORS

THIS AGREEMENT is dated this ____ day of _____, _____ and is entered into, by and between:

(1) **[Full Legal Name]** having its registered and principal place of business located at **[Address]** (the "Scheduling Coordinator");

and

(2) **California Independent System Operator Corporation**, a California nonprofit public benefit corporation having a principal executive office located at such place in the State of California as the ISO Governing Board may from time to time designate, initially 151 Blue Ravine Road, Folsom, California 95630 (the "ISO").

The Scheduling Coordinator and the ISO are hereinafter referred to as the "Parties".

Whereas:

- A.** The ISO Tariff provides that a Scheduling Coordinator may submit dynamic schedules to the ISO from System Resources.
- B.** The Scheduling Coordinator is currently Scheduling Coordinator for a System Resource associated with a power plant(s) interconnected in a Control Area other than the ISO Control Area (the "Host Control Area").
- C.** The Scheduling Coordinator wishes to implement and operate a dynamic functionality that allows scheduling of Energy, Supplemental Energy, and Energy associated with Spinning Reserve and Non-Spinning Reserve dynamically from a System Resource into the ISO Control Area from the Host Control Area and, therefore, wishes to undertake to the ISO that it will comply with the applicable provisions of the ISO Tariff.
- D.** The Parties are entering into this Agreement in order to establish the terms and conditions on which the ISO and the Scheduling Coordinator will discharge their respective duties and responsibilities under the ISO Tariff.

NOW THEREFORE, in consideration of the mutual covenants set forth herein, **THE PARTIES AGREE** as follows:

ARTICLE I

DEFINITIONS AND INTERPRETATION

Master Definitions Supplement. All terms and expressions used in this Agreement shall have the same meaning as those contained in the Master Definitions Supplement to the ISO Tariff.

Rules of Interpretation. The following rules of interpretation and conventions shall apply to this Agreement:

- (a) if there is any inconsistency between this Agreement and the ISO Tariff, the ISO Tariff will prevail to the extent of the inconsistency;
- (b) the singular shall include the plural and vice versa;

- (c) the masculine shall include the feminine and neutral and vice versa;
- (d) "includes" or "including" shall mean "including without limitation";
- (e) references to a Section, Article or Schedule shall mean a Section, Article or a Schedule of this Agreement, as the case may be, unless the context otherwise requires;
- (f) a reference to a given agreement 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;
- (g) unless the context otherwise requires, references to any law shall be deemed references to such law as it may be amended, replaced or restated from time to time;
- (h) unless the context otherwise requires, any reference to a "person" includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization or other entity, in each case whether or not having separate legal personality;
- (i) unless the context otherwise requires, any reference to a Party includes a reference to its permitted successors and assigns;
- (j) any reference to a day, week, month or year is to a calendar day, week, month or year; and the captions and headings in this Agreement are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Agreement.

ARTICLE II

ACKNOWLEDGEMENTS OF SCHEDULING COORDINATOR AND ISO

- 2.1 ISO Responsibility.** The Parties acknowledge that the ISO is responsible for the efficient use and reliable operation of the ISO Controlled Grid consistent with achievement of planning and operating reserve criteria no less stringent than those established by the Western Electricity Coordinating Council and the North American Electric Reliability Council and further acknowledges that the ISO may not be able to satisfy fully these responsibilities if the Scheduling Coordinator fails to fully comply with all of its obligations under this Agreement and the ISO Tariff.

ARTICLE III

TERM AND TERMINATION

- 3.1 Effective Date.** This Agreement shall be effective as of the date set forth above, unless accepted for filing and made effective by FERC on some other date, if FERC filing is required, and shall remain in full force and effect until terminated pursuant to Section 3.2 of this Agreement.

3.2 Termination

3.2.1 Termination by ISO. Subject to Section 3.2.2, the ISO may terminate this Agreement by giving written notice of termination in the event that the ISO's agreement with the Host Control Area has terminated or the Scheduling Coordinator commits any material default under this Agreement and/or the ISO Tariff which, if capable of being remedied, is not remedied within thirty (30) days after the ISO has given, to the Scheduling Coordinator, written notice of the default, unless excused by reason of Uncontrollable Forces in accordance with Article X of this Agreement. With respect to any notice of termination given pursuant to this Section, the ISO must file a timely notice of termination with FERC, if this Agreement has been filed with FERC, or must otherwise comply with the requirements of FERC Order No. 2001 and related FERC orders. The filing of the notice of termination by the ISO will be considered timely if: (1) the filing of the notice of termination is made after the preconditions for termination have been met, and (2) the ISO files the notice of termination within sixty (60) days after issuance of the notice of default. This Agreement shall terminate upon acceptance by FERC of such a notice of termination, if filed with FERC, or thirty (30) days after the date of the ISO's notice of default, if terminated in accordance with the requirements of FERC Order No. 2001 and related FERC orders.

3.2.2 Limitation on ISO Termination. Notwithstanding the provisions of Section 3.2.1, in the event of noncompliance with the provisions of the ISO's Standards, the ISO shall have the right to terminate this Agreement after three (3) instances of noncompliance. In the event that the ISO determines that the Scheduling Coordinator has failed to comply with the ISO's Standards, the ISO will provide written notice to that effect to the Scheduling Coordinator, and the Scheduling Coordinator shall have seven (7) days to correct the non-compliant condition(s). If the ISO determines that Scheduling Coordinator has not corrected the non-compliant condition(s) within seven (7) days after the third notice of noncompliance, the ISO may, by further written notice to the Scheduling Coordinator, terminate this Agreement and the existing functionality and arrangements described herein pursuant to Section 3.2.1, but without providing for the additional thirty (30)-day cure period otherwise provided in Section 3.2.1.

3.2.3 Termination by Scheduling Coordinator. In the event that the Scheduling Coordinator no longer wishes to submit dynamic schedules to the ISO, it may terminate this Agreement, on giving the ISO ninety (90) days written notice. With respect to any notice of termination given pursuant to this Section, the ISO must file a timely notice of termination with FERC, if this Agreement has been filed with FERC, or must otherwise comply with the requirements of FERC Order No. 2001 and related FERC orders. The filing of the notice of termination by the ISO will be considered timely if: (1) the request to file a notice of termination is made after the preconditions for termination have been met, and (2) the ISO files the notice of termination within thirty (30) days of receipt of such request. This Agreement shall terminate upon acceptance by FERC of such a notice of termination, if such notice is required to be filed with FERC, or upon ninety (90) days after the ISO's receipt of the Scheduling Coordinator's notice of default, if terminated in accordance with the requirements of FERC Order No. 2001 and related FERC orders.

ARTICLE IV

GENERAL TERMS AND CONDITIONS

4.1 Dynamic Scheduling Requirements and Obligations

- 4.1.1** The dynamic functionality established under this Agreement shall be implemented and operated in accordance with ISO Tariff Section 4.5.4.3, other applicable provisions of the ISO Tariff, all applicable NERC and WECC policies, requirements, and provisions, and the ISO's "*Standards for Dynamic Imports of Energy, Supplemental Energy, and Energy Associated with Non-Regulation Ancillary Services*" ("Standards") posted on the ISO Home Page: "www.caiso.com".
- 4.1.2** The maximum allowable dynamic power transfer (in MW) from the Scheduling Coordinator's System Resource(s) shall be as set forth in Schedule 1 and will be referred to as "Pmax" in all ISO scheduling and control systems.
- 4.1.3** The Scheduling Coordinator warrants that the power plant(s) listed in Schedule 1 is interconnected within the Host Control Area specified in Schedule 1, placing both the plant(s) as well as the associated System Resource under the operational jurisdiction of the Host Control Area.
- 4.1.4** The ISO intertie associated with the System Resource(s) is set forth in Schedule 1. The Scheduling Coordinator may request, and the ISO may agree, at its sole discretion, to change the foregoing ISO intertie association, subject to any limitations set forth in the Standards.
- 4.1.5** Unless explicitly agreed otherwise, dynamic functionalities implemented between the ISO and the Scheduling Coordinator may provide only for imports from the System Resource(s) listed in Schedule 1 to the ISO.
- 4.1.6 Identification of System Resources.** The Scheduling Coordinator has identified the System Resources that it represents in Schedule 1.
- 4.1.7 Notification of Changes.** Sixty (60) days prior to changing any technical information in Schedule 1, the Scheduling Coordinator shall notify the ISO of the proposed changes. Pursuant to Section 8.10.1 of the ISO Tariff, the ISO may verify, inspect and test the capacity and operating characteristics provided in the revised Schedule 1. Unless the Scheduling Coordinator 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 ISO's Master File, provided the Scheduling Coordinator submits the changed information by the applicable deadline and is tested by the deadline.
- 4.2 Agreement Subject to ISO Tariff.** The Parties will comply with all applicable provisions of the ISO Tariff, including Sections 4.5.4.3 and 8.4.4. This Agreement shall be subject to the ISO Tariff, which shall be deemed to be incorporated herein.
- 4.3 Obligations Relating to Ancillary Services**
- 4.3.1 Submission of Bids.** When the Scheduling Coordinator submits a bid for Ancillary Services, the Scheduling Coordinator 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.

ARTICLE V

PENALTIES AND SANCTIONS

- 5.1 Uninstructed Deviations.** Except for operating emergency situations, real time Energy transfers may not vary from the Final Hour Ahead Schedule as adjusted by any Dispatch Instructions by more than the greater of five (5) MW or three percent (3%) of the net dependable capacity (Pmax) of the System Resource, integrated across a ten-minute interval. If such defined performance band is exceeded by any amount in more than five percent (5%) of the ten-minute intervals on three successive days, then such deviations shall constitute one event of non-compliance with the ISO's Standards pursuant to Section 3.2.2. Deviations from dynamic Energy schedules will also be subject to Uninstructed Deviation Penalties pursuant to Section 11.2.4.1.2 and related provisions of the ISO Tariff.
- 5.2 General.** The Scheduling Coordinator shall be subject to all penalties made applicable to dynamic imports from System Resources set forth in the ISO Tariff.

ARTICLE VI

COSTS

- 6.1 Operating and Maintenance Costs.** The Scheduling Coordinator shall be responsible for all its costs incurred in connection with dynamic scheduling and compliance by the System Resources identified in Schedule 1 for the purpose of meeting its obligations under this Agreement.

ARTICLE VII

DISPUTE RESOLUTION

- 7.1 Dispute Resolution.** The Parties shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. In the event any dispute is not settled, the Parties shall adhere to the ISO ADR Procedures set forth in Section 13 of the ISO Tariff, which is incorporated by reference, except that any reference in Section 13 of the ISO Tariff to Market Participants shall be read as a reference to the Scheduling Coordinator and references to the ISO Tariff shall be read as references to this Agreement.

ARTICLE VIII

REPRESENTATIONS AND WARRANTIES

- 8.1 Representation and Warranties.** Each Party represents and warrants that the execution, delivery and performance of this Agreement by it has been duly authorized by all necessary corporate and/or governmental actions, to the extent authorized by law.

ARTICLE IX

LIABILITY

- 9.1 Liability.** The provisions of Section 14 of the ISO Tariff will apply to liability arising under this Agreement, except that all references in Section 14 of the ISO Tariff to Market Participants shall be read as references to the Scheduling Coordinator and references to the ISO Tariff shall be read as references to this Agreement.

ARTICLE X

UNCONTROLLABLE FORCES

- 10.1 Uncontrollable Forces Tariff Provisions.** Section 14 of the ISO Tariff shall be incorporated by reference into this Agreement except that all references in Section 14 of the ISO Tariff to Market Participants shall be read as a reference to the Scheduling Coordinator and references to the ISO Tariff shall be read as references to this Agreement.

ARTICLE XI

MISCELLANEOUS

- 11.1 Assignments.** Either Party may assign or transfer any or all of its rights and/or obligations under this Agreement with the other Party's prior written consent in accordance with Section 22.2 of the ISO Tariff. Such consent shall not be unreasonably withheld. Any such transfer or assignment shall be conditioned upon the successor in interest accepting the rights and/or obligations under this Agreement as if said successor in interest was an original Party to this Agreement.
- 11.2 Notices.** Any notice, demand or request which may be given to or made upon either Party regarding this Agreement shall be made in accordance with Section 22.4 of the ISO Tariff. A Party must update the information in Schedule 2 of this Agreement as information changes. Such changes shall not constitute an amendment to this Agreement.
- 11.3 Waivers.** Any waivers at any time by either 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.

- 11.4 Governing Law and Forum.** This Agreement shall be deemed to be a contract made under, and for all purposes shall be governed by and construed in accordance with, the laws of the State of California, except its conflict of law provisions. The Parties irrevocably consents that any legal action or proceeding arising under or relating to this Agreement to which the ISO ADR Procedures do not apply, shall be brought in any of the following forums, as appropriate: any court of the State of California, any federal court of the United States of America located in the State of California, or, where subject to its jurisdiction, before the Federal Energy Regulatory Commission.
- 11.5 Consistency with Federal Laws and Regulations.** This Agreement shall incorporate by reference Section 22.9 of the ISO Tariff as if the references to the ISO Tariff were referring to this Agreement.
- 11.6 Merger.** This Agreement constitutes the complete and final agreement of the Parties with respect to the subject matter hereto and supersedes all prior agreements, whether written or oral, with respect to such subject matter.
- 11.7 Severability.** If any term, covenant, or condition of this Agreement or the application or effect of any such term, covenant, or condition is held invalid as to any person, entity, or circumstance, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in force and effect to the maximum extent permitted by law, and all other terms, covenants, and conditions of this Agreement and their application shall not be affected thereby, but shall remain in force and effect and the Parties shall be relieved of their obligations only to the extent necessary to eliminate such regulatory or other determination unless a court or governmental agency of competent jurisdiction holds that such provisions are not separable from all other provisions of this Agreement.
- 11.8 Section Headings.** Section headings provided in this Agreement are for ease of reading and are not meant to interpret the text in each Section.
- 11.9 Amendments.** This Agreement and the Schedules attached hereto may be amended from time to time by the mutual agreement of the Parties in writing. Amendments that require FERC approval shall not take effect until FERC has accepted such amendments for filing and made them effective. If the amendment does not require FERC approval, the amendment will be filed with FERC for information. Nothing contained herein shall be construed as affecting in any way the right of the ISO to unilaterally make application to FERC for a change in the rates, terms and conditions of this Agreement under Section 205 of the FPA and pursuant to FERC's rules and regulations promulgated thereunder.
- 11.10 Counterparts.** This Agreement may be executed in one or more counterparts at different times, each of which shall be regarded as an original and all of which, taken together, shall constitute one and the same Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed on behalf of each by and through their authorized representatives as of the date hereinabove written.

California Independent System Operator Corporation

By: _____

Name: _____

Title: _____

Date: _____

NAME OF SCHEDULING COORDINATOR

By: _____

Name: _____

Title: _____

Date: _____

SCHEDULE 1

SYSTEM RESOURCES AND CONTROL AREA INFORMATION

[Sections 4.1.2, 4.1.3, 4.1.5]

Description of System Resource(s), including Associated Power Plants and Pmax Values:

ISO Intertie:

Host Control Area:

Intermediate Control Areas:

SCHEDULE 2

NOTICES
[Section 11.2]

Scheduling Coordinator

Name of Primary
Representative: _____
Title: _____
Company: _____
Address: _____
City/State/Zip Code _____
Email Address: _____
Phone: _____
Fax No: _____

Name of Alternative
Representative: _____
Title: _____
Company: _____
Address: _____
City/State/Zip Code _____
Email Address: _____
Phone: _____
Fax No: _____

ISO

Name of Primary

Representative: _____

Title: _____

Address: _____

City/State/Zip Code _____

Email Address: _____

Phone: _____

Fax No: _____

Name of Alternative

Representative: _____

Title: _____

Address: _____

City/State/Zip Code _____

Email Address: _____

Phone: _____

Fax No: _____

ISO TARIFF APPENDIX B.6
Meter Service Agreement for ISO Metered Entities

CALIFORNIA INDEPENDENT SYSTEM OPERATOR

AND

[ISO METERED ENTITY]

**METER SERVICE AGREEMENT
FOR ISO METERED ENTITIES**

**METER SERVICE AGREEMENT
FOR ISO METERED ENTITIES**

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

(1) **[Full legal name]** having its registered and principal place of business located at **[Address]**
(the "ISO Metered Entity");

and

(2) **California Independent System Operator Corporation**, a California nonprofit public benefit corporation having a principal executive office located at such place in the State of California as the ISO Governing Board may from time to time designate, initially 151 Blue Ravine Road, Folsom, California 95630 (the "ISO").

The ISO Metered Entity and the ISO are hereinafter referred to as the "Parties".

Whereas:

- A.** Section 10 of the ISO Tariff requires the ISO to establish meter service agreements with ISO Metered Entities for the collection and transfer of Meter Data.
- B.** Section 10 of the ISO Tariff further provides that an ISO Metered Entity shall certify its revenue quality meters and Section 10 provides that ISO Metered Entities shall make Meter Data available to MDAS.
- C.** The Parties are entering into this Agreement in order to establish the terms and conditions upon which the ISO and the ISO Metered Entity shall discharge their respective duties and responsibilities pursuant to this Agreement, and the ISO Tariff.
- D.** All obligations and responsibilities included in this Agreement may be set forth in further detail in the ISO Tariff.

NOW THEREFORE, in consideration of the mutual covenants set forth herein, **THE PARTIES AGREE** as follows:

ARTICLE I

1.1 Master Definitions Supplement. Unless defined in Section 1.2 of this Agreement, all terms and expressions used in this Agreement shall have the same meaning as those contained in the Master Definitions Supplement to the ISO Tariff.

1.2 Special Definitions for this Agreement. In this Agreement, the following words and expressions shall have the meanings set forth below:

“Authorized Users” means users authorized by the ISO Metered Entity to access the Meter Data of that ISO Metered Entity held by the ISO.

“ISO Authorized Inspector” has the meaning as defined in Appendix A of the ISO Tariff.

“ISO Metered Entity” means:

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

- ii. an Eligible Customer; or
 - iii. an End-User other than an End-User that purchases all of its Energy from the UDC in whose Service Area it is located; and
- (b) any one of the following entities:
- i. a Participating Generator;
 - ii. a Participating TO in relation to its Tie Point Meters with other TOs or Control Areas; or
 - iii. a Participating Load.

“MDAS” means the ISO revenue metering data acquisition and processing system.

“Metering Facilities” means revenue quality meters, instrument transformers, secondary circuitry, secondary devices, meter data servers, related communication facilities and other related local equipment.

“SC” means Scheduling Coordinator.

1.3 Rules of Interpretation. The following rules of interpretation and conventions shall apply to this Agreement:

- (a) if there is any inconsistency between this Agreement and the ISO Tariff, the ISO Tariff will prevail to the extent of the inconsistency;
- (b) the singular shall include the plural and vice versa;
- (c) the masculine shall include the feminine and neutral and vice versa;
- (d) “includes” or “including” shall mean “including without limitation”;
- (e) references to a section, article or schedule shall mean a section, article or a schedule of this Agreement, as the case may be, unless the context otherwise requires;
- (f) a reference to a given agreement 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;
- (g) unless the context otherwise requires, references to any law shall be deemed references to such law as it may be amended, replaced or restated from time to time;
- (h) unless the context otherwise requires, any reference to a “person” includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization or other entity, in each case whether or not having separate legal personality;

- (i) unless the context otherwise requires, any reference to a Party includes a reference to its permitted successors and assigns;
- (j) any reference to a day, week, month or year is to a calendar day, week, month or year;
- (m) the captions and headings in this Agreement are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Agreement; and
- (n) references to the ISO Tariff and other ISO Documents shall be interpreted in accordance with any exceptions or exemptions to such as may have been granted by the ISO.

ARTICLE II

TERM AND TERMINATION

- 2.1 Effective Date.** This Agreement shall be effective as of the later of the date of execution of this Agreement, or the date it is accepted and made effective by FERC and shall remain in full force and effect until terminated by operation of law or pursuant to Section 2.2 of this Agreement.
- 2.2 Termination**
- 2.2.1 Termination by ISO.** Subject to Section 4.2, the ISO may terminate this Agreement by giving written notice of termination in the event that the ISO Metered Entity commits any default under this Agreement and/or the ISO Tariff which, if capable of being remedied, is not remedied within thirty (30) days after the ISO has given it written notice of the default, unless excused by reason of Uncontrollable Force in accordance with Section 14 of the ISO Tariff. With respect to any notice of termination given pursuant to this Section, the ISO must file a timely notice of termination with FERC. The filing of the notice of termination by the ISO will be considered timely if: (1) the request to file a notice of termination is made after the preconditions for termination have been met, and (2) the ISO files the notice of termination within 30 days of receipt of such request. This Agreement shall terminate upon acceptance by FERC of such notice of termination.
- 2.2.2 Termination by ISO Metered Entity.** In the event that the ISO Metered Entity wishes to terminate this Agreement, the ISO Metered Entity shall give the ISO ninety (90) days written notice. With respect to any notice of termination given pursuant to this Section, the ISO must file a timely notice of termination with FERC. The filing of the notice of termination by the ISO will be considered timely if: (1) the request to file a notice of termination is made after the preconditions for termination have been met, and (2) the ISO files the notice of termination within 30 days of receipt of such request. This Agreement shall terminate upon acceptance by FERC of such notice of termination.

ARTICLE III

GENERAL TERMS AND CONDITIONS

- 3.1 Agreement Subject to ISO Tariff.** This Agreement shall be subject to the provisions of the ISO Tariff which shall be deemed to be incorporated herein, as the same may be changed or superseded from time to time. The Parties agree that they will comply with the provisions of Section 10 and Appendix O of the ISO Tariff.
- 3.2 Obligations and Rights of the ISO Metered Entity.**
- 3.2.1 Submission of Meter Data through MDAS.** The ISO Metered Entity agrees to make available to the ISO through MDAS its Meter Data in accordance with the ISO Tariff. The ISO's requirements regarding the frequency with which it requires Meter Data to be made available to it through MDAS by the ISO Metered Entity are referred to in the ISO Tariff.
- 3.2.2 Meter Information.** The ISO Metered Entity shall provide in the format prescribed by Schedule 1 to this Agreement the required information with respect to all of its meters used to provide Meter Data to the ISO. The ISO Metered Entity must immediately notify the ISO of any changes to the information provided to the ISO in accordance with this Section 3.2.2 and provide the ISO with any information in relation to such change as reasonably requested by the ISO. The ISO Metered Entity shall have the right to modify Schedule 1, which modification shall not constitute an amendment to this Agreement. Such modification shall be effective upon receipt of notice by the ISO.
- 3.2.3 Transformer and/or Line Loss Correction Factors.** If the ISO Metered Entity uses low voltage side metering, it shall use the ISO approved transformer and/or line loss correction factor referred to in the ISO Tariff.
- 3.2.4 Rights to Access Metering Facilities.** The ISO Metered Entity shall use its best efforts to procure any rights necessary for the ISO to access all Metering Facilities of the ISO Metered Entity to fulfill its obligations under the ISO Tariff and its obligations under this Agreement. If, after using its best efforts, the ISO Metered Entity is unable to provide the ISO with such access rights, the ISO Metered Entity shall ensure that one of its employees is an ISO Authorized Inspector and such employee undertakes, at the ISO's request, the certification, testing, inspection and/or auditing of those Metering Facilities in accordance with the procedures established pursuant to the ISO Tariff, including the requirement to complete and provide to the ISO all necessary documentation. The ISO acknowledges that it will not be prevented from fulfilling its obligations under the ISO Tariff or this Agreement by reason of the fact that it is provided with escorted access to the Metering Facilities of the ISO Metered Entity.
- 3.2.5 Security and Validation Procedures.** The security measures and the validation, editing and estimation procedures that the ISO will apply to Meter Data made available to the ISO by the ISO Metered Entity shall be as referred to in the ISO Tariff.

3.3 Obligations and Rights of the ISO.

3.3.1 Direct Polling of MDAS. The ISO shall allow the Scheduling Coordinator representing the ISO Metered Entity and all Authorized Users to directly poll MDAS for the Meter Data relating to the ISO Metered Entity in accordance with the procedures referred to in the ISO Tariff.

3.3.2 ISO as Third-Party Beneficiary. The ISO shall be a third-party beneficiary to any future agreement between the ISO Metered Entity and any other party relating to the Metering Facilities of the ISO Metered Entity for the purpose of granting the ISO access to any relevant information, records and facilities as needed by the ISO to fulfill its obligations under the ISO Tariff and its obligations under this Agreement.

3.3.3 Remote and Local Access to Metering Data. The ISO shall provide the ISO Metered Entity any password or other requirements necessary for the ISO Metered Entity to access its Metered Data remotely or locally at the Meter.

3.4 Exemptions Granted by the ISO. Any exemptions provided for under the ISO Tariff that are granted by the ISO shall be set forth in Schedule 2 of this Agreement. Any amendment or addition to Schedule 2 shall not constitute an amendment to this Agreement.

ARTICLE IV

PENALTIES AND SANCTIONS

4.1 Penalties. If an ISO Metered Entity provides inaccurate or incorrect Meter Data or fraudulent Meter Data to the ISO, the ISO shall be entitled to impose penalties and sanctions, including but not limited to suspension of trading rights following 14 days written notice to the ISO Metered Entity. Fraudulent Meter Data means any Meter Data provided to the ISO by the ISO Metered Entity that it knows to be false, incorrect or incomplete at the time it provided that Meter Data to the ISO. All penalties and sanctions shall be set forth in Schedule 4 Part A to this Agreement. No penalties or sanctions, including suspension of trading rights, 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 ISO Metered Entity 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 ISO Metered Entity.

4.2 Corrective Measures. If the ISO Metered Entity fails to meet or maintain the standards for Metering Facilities or comply with the audit or test procedures as referred to in the ISO Tariff, the ISO shall be permitted to take corrective measures. The corrective measures and rights the ISO may exercise upon any failure by any entity to meet those standards for Metering Facilities or to comply with the audit or test procedures shall be set forth in Schedule 4 Part B.

ARTICLE V

ACCESS TO METERING DATA

- 5.1 Authorized Users.** In addition to the persons referred to in the ISO Tariff, including the ISO Metered Entity and the relevant Scheduling Coordinator, as being entitled to access Meter Data on MDAS, the ISO Metered Entity may set forth in Schedule 3 of this Agreement any additional authorized users that shall be entitled to access the ISO Metered Entity's Settlement Quality Meter Data held by the ISO. The ISO Metered Entity shall include in Schedule 3 as authorized users the relevant UDCs and TOs. The ISO shall provide the authorized users with any password or other information necessary to access the ISO Metered Entity's Settlement Quality Metered Data held by the ISO on MDAS. Any amendment or addition to Schedule 3 shall not constitute an amendment to this Agreement.

ARTICLE VI

COSTS

- 6.1 Certification, Inspection and Auditing of Meters.** The ISO Metered Entity shall be responsible for all reasonable costs incurred by the ISO or an ISO Authorized Inspector in connection with them carrying out the certification, inspection, testing or auditing of the meters identified in Schedule 1 from which the ISO Metered Entity provides Meter Data to the ISO. The ISO or ISO Authorized Inspector will furnish the ISO Metered Entity, upon request, an itemized bill for such costs.

ARTICLE VII

DISPUTE RESOLUTION

- 7.1 Dispute Resolution.** The Parties shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. In the event any dispute is not settled, the Parties shall adhere to the ISO ADR Procedures set forth in Section 13 of the ISO Tariff, which is incorporated by reference, except that all reference in Section 13 of the ISO Tariff to Market Participants shall be read as a reference to the ISO Metered Entities and references to the ISO Tariff shall be read as references to this Agreement.

ARTICLE VIII

REPRESENTATIONS AND WARRANTIES

- 8.1 Representations and Warranties.** Each Party represents and warrants that the execution, delivery and performance of this Agreement by it has been duly authorized by all necessary corporate and/or governmental actions, to the extent authorized by law.

- 8.2 Necessary Approvals.** The ISO Metered Entity represents that all necessary approvals, permits, licenses, easements, right of way or access to install, own and operate its meters have been or will be obtained by the ISO Metered Entity prior to the effective date of this Agreement.

ARTICLE IX

LIABILITY AND INDEMNIFICATION

- 9.1 Liability and Indemnification.** The provisions of Section 14 of the ISO Tariff will apply to liability arising under this Agreement, except that all references in Section 14 of the ISO Tariff to Market Participants shall be read as references to the ISO Metered Entity and references to the ISO Tariff shall be read as references to this Agreement.

ARTICLES X

UNCONTROLLABLE FORCES

- 10.1 Uncontrollable Forces Tariff Provisions.** Section 14 of the ISO Tariff shall be incorporated by reference into this Agreement except that all references in Section 14 of the ISO Tariff to Market Participants shall be read as references to the ISO Metered Entity and all references to the ISO Tariff shall be read as references to this Agreement.

ARTICLE XI

MISCELLANEOUS

- 11.1 Assignments.** Either Party may assign or transfer any or all of its rights and/or obligations under this Agreement with the other Party's prior written consent in accordance with Section 22.2 of the ISO Tariff. Such consent shall not be unreasonably withheld. Any such transfer or assignment shall be conditioned upon the successor in interest accepting the rights and/or obligations under this Agreement as if said successor in interest was an original Party to this Agreement.
- 11.2 Notices.** Any notice, demand or request which may be given to or made upon either Party regarding this Agreement shall be made in accordance with Section 22.4 of the ISO Tariff. A Party must update the information in Schedule 5 as information changes. Such changes shall not constitute an amendment to this Agreement.
- 11.3 Waivers.** Any waiver at any time by either 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 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.

- 11.4 Governing Law and Forum.** This Agreement shall be deemed to be a contract made under and for all purposes shall be governed by and construed in accordance with the laws of the State of California, except its conflict of law provisions. The Parties irrevocably consent that any legal action or proceeding arising under or relating to this Agreement to which the ISO ADR Procedures do not apply shall be brought in any of the following forums, as appropriate: any court of the State of California, any federal court of the United States of America located in the State of California or, where subject to its jurisdiction, before the Federal Energy Regulatory Commission.
- 11.5 Consistency with Federal Laws and Regulations.** This Agreement shall incorporate by reference Section 22.9 of the ISO Tariff as if the references to the ISO Tariff were referring to this Agreement.
- 11.6 Merger.** This Agreement constitutes the complete and final agreement of the Parties with respect to the subject matter hereto and supersedes all prior agreements, whether written or oral, with respect to such subject matter.
- 11.7 Severability.** If any term, covenant, or condition of this Agreement or the application or effect of any such term, covenant, or condition is held invalid as to any person, entity, or circumstance, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in force and effect to the maximum extent permitted by law, and all other terms, covenants, and conditions of this Agreement and their application shall not be affected thereby, but shall remain in force and effect and the parties shall be relieved of their obligations only to the extent necessary to eliminate such regulatory or other determination unless a court or governmental agency of competent jurisdiction holds that such provisions are not separable from all other provisions of this Agreement.
- 11.8 Amendments.** This Agreement and the Schedules attached hereto may be amended from time to time by the mutual agreement of the Parties in writing. Amendments that are subject to FERC approval shall not take effect until FERC has accepted such amendments for filing and has made them effective. If the amendment does not require FERC approval, the amendment will be filed with FERC for information.
- 11.9 Counterparts.** This Agreement may be executed in one or more counterparts at different times, each of which shall be regarded as an original and all of which, taken together, shall constitute one and the same Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed on behalf of each by and through their authorized representatives as of the date hereinabove written.

California Independent System Operator Corporation

By: _____

Name: _____

Title: _____

Date: _____

Full legal name of ISO Metered Entity

By: _____

Name: _____

Title: _____

Date: _____

SCHEDULE 1
METER INFORMATION
[Section 3.3.2]

Resource ID/Meter Number _____
Name of the Facility _____
Location (address if applicable) _____

SCHEDULE 2

EXEMPTIONS FROM METERING STANDARDS AND OTHER REQUIREMENTS

[Section 3.4]

SCHEDULE 3

**ACCESS TO METER DATA
AND
AUTHORIZED USERS
[Section 5.1]**

List authorized users and any restrictions or limitations placed on them.

SCHEDULE 4
PART A
ISO IMPOSED PENALTIES AND SANCTIONS
[Section 4.1]

TO BE INSERTED UPON FERC APPROVAL

PART B
CORRECTIVE MEASURES
[SECTION 4.2]

TO BE DEVELOPED

SCHEDULE 5

NOTICE

[Section 11.2]

Name of Primary

Representative: _____

Title: _____

Company: _____

Address: _____

City/State/Zip Code: _____

Email address: _____

Phone: _____

Fax: _____

Name of Alternative

Representative: _____

Title: _____

Company: _____

Address: _____

City/State/Zip Code: _____

Email address: _____

Phone: _____

Fax: _____

ISO:

Name of Primary

Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email address: _____

Phone: _____

Fax: _____

Name of Alternative

Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email address: _____

Phone: _____

Fax: _____

ISO TARIFF APPENDIX B.7
Meter Service Agreement for Scheduling Coordinators

CALIFORNIA INDEPENDENT SYSTEM OPERATOR

AND

[SC]

**METER SERVICE AGREEMENT
FOR SCHEDULING COORDINATORS**

**METER SERVICE AGREEMENT
FOR SCHEDULING COORDINATORS**

THIS AGREEMENT is dated this ____ day of _____, ____ and is entered into, by and between:

(1) **[Full legal name]** having its registered and principal place of business located at **[Address]**
(the "SC");

and

(2) **California Independent System Operator Corporation**, a California non-profit public benefit corporation having a principal executive office located at such place in the State of California as the ISO Governing Board may from time to time designate, initially 151 Blue Ravine Road, Folsom, California 95630 (the "ISO").

The Scheduling Coordinator and the ISO are hereinafter referred to as the "Parties".

Whereas:

- A.** Section 10 of the ISO Tariff requires the ISO to enter into a meter service agreement with each Scheduling Coordinator responsible for providing Settlement Quality Meter Data for Scheduling Coordinator Metered Entities that it represents.
- B.** Section 10 of the ISO Tariff requires Scheduling Coordinators to ensure that the Scheduling Coordinator Metered Entities that they represent adhere to the requirements and standards for Metering Facilities set forth in Section 10.6.
- C.** The Parties are entering into this Agreement in order to establish the terms and conditions upon which the ISO and the Scheduling Coordinator shall discharge their respective duties and responsibilities pursuant to this Agreement and the ISO Tariff.
- D.** All obligations and responsibilities included in this Agreement may be set forth in further detail in the ISO Tariff.

NOW THEREFORE, in consideration of the mutual covenants set forth herein, **THE PARTIES AGREE** as follows:

ARTICLE I

DEFINITIONS AND INTERPRETATION

1.1 Master Definitions Supplement. Unless defined in Section 1.2 of this Agreement, all terms and expressions used in this Agreement shall have the same meaning as those contained in the Master Definitions Supplement to the ISO Tariff.

1.2 Special Definitions for this Agreement. In this Agreement, the following words and expressions shall have the meanings set forth below:

“ISO Authorized Inspector” has the meaning as defined in the ISO Tariff.

“ISO Metered Entity” means:

- (a) any one of the following entities that is directly connected to the ISO Controlled Grid:
 - i. a Generator other than a Generator that sells all of its Energy (excluding any Energy consumed by auxiliary load equipment electrically connected to that Generator at the same point) and Ancillary Services to the UDC in whose Service Area it is located;
 - ii. an Eligible Customer; or
 - iii. an End-User other than an End-User that purchases all of its Energy from the UDC in whose Service Area it is located; and
- (b) any one of the following entities:
 - i. a Participating Generator;
 - ii. a Participating TO in relation to its Tie Point Meters with other TOs or Control Areas; or
 - iii. a Participating Load.

“MDAS” means the ISO’s revenue metering data acquisition and processing system.

“Metering Facilities” means revenue quality meters, instrument transformers, secondary circuitry, secondary devices, meter data servers, related communication facilities and other related local equipment.

“SC” means Scheduling Coordinator.

“Scheduling Coordinator Metered Entity” or **“SC Metered Entity”** means a Generator, Eligible Customer or End-User that is not an ISO Metered Entity.

1.3 Rules of Interpretation. The following rules of interpretation and conventions shall apply to this Agreement:

- (a) if there is any inconsistency between this Agreement and the ISO Tariff, the ISO Tariff will prevail to the extent of the inconsistency;
- (b) the singular shall include the plural and vice versa;
- (c) the masculine shall include the feminine and neutral and vice versa;
- (d) "includes" or "including" shall mean "including without limitation";
- (e) references to a section, article or schedule shall mean a section, article or a schedule of this Agreement, as the case may be, unless the context otherwise requires;
- (f) a reference to a given agreement 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;
- (g) unless the context otherwise requires, references to any law shall be deemed references to such law as it may be amended, replaced or restated from time to time;
- (h) unless the context otherwise requires, any reference to a "person" includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization or other entity, in each case whether or not having separate legal personality;
- (i) unless the context otherwise requires, any reference to a Party includes a reference to its permitted successors and assigns;
- (j) any reference to a day, week, month or year is to a calendar day, week, month or year;
- (k) the captions and headings in this Agreement are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Agreement; and
- (l) references to the ISO Tariff and other ISO Documents shall be interpreted in accordance with any exceptions or exemptions to such as may have been granted by the ISO.

ARTICLE II

TERM AND TERMINATION

2.1 Effective Date. This Agreement shall be effective as of the later of the date of execution of this Agreement, or the date it is accepted and made effective by FERC, and shall remain in full force and effect until terminated by operation of law or pursuant to Section 2.2 of this Agreement.

2.2 Termination

2.2.1 Termination by ISO. Subject to Section 14 the ISO may terminate this Agreement by giving written notice of termination in the event that the Scheduling Coordinator commits any default under this Agreement and/or the ISO Tariff which, if capable of being remedied, is not remedied within thirty (30) days after the ISO has given it written notice of the default, unless excused by reason of Uncontrollable Force in accordance with Section 15 of the ISO Tariff. With respect to any notice of termination given pursuant to this Section, the ISO must file a timely notice of termination with FERC. The filing of the notice of termination by the ISO will be considered timely if: (1) the request to file a notice of termination is made after the preconditions for termination have been met, and (2) the ISO files the notice of termination within 30 days of receipt of such request. This Agreement shall terminate upon acceptance by FERC of such notice of termination.

2.2.2 Termination by SC. In the event that the Scheduling Coordinator wishes to terminate this Agreement, the Scheduling Coordinator shall give the ISO ninety (90) days written notice. With respect to any notice of termination given pursuant to this Section, the ISO must file a timely notice of termination with FERC. The filing of the notice of termination by the ISO will be considered timely if: (1) the request to file a notice of termination is made after the preconditions for termination have been met, and (2) the ISO files the notice of termination within 30 days of receipt of such request. This Agreement shall terminate upon acceptance by FERC of such a notice of termination.

ARTICLE III

GENERAL TERMS AND CONDITIONS

3.1 Agreement Subject to ISO Tariff . This Agreement shall be subject to the provisions of the ISO Tariff which shall be deemed to be incorporated herein, as the same may be changed or superseded from time to time. The Parties agree that they will comply with the provisions of Section 10 of the ISO Tariff.

3.2 Requirements and Standards for Metering Facilities. The Scheduling Coordinator shall ensure that the Scheduling Coordinator Metered Entities it represents shall adhere to the requirements and standards for Metering Facilities of its Local Regulatory Authority. If that Scheduling Coordinator Metered Entity's Local Regulatory Authority has not set any requirements or standards in relation to any of its Metering Facilities, the Scheduling Coordinator representing that Scheduling Coordinator Metered Entity must comply with the requirements and standards for those Metering Facilities as set forth in this Agreement and the ISO Tariff.

3.3 Obligations and Rights of the Scheduling Coordinator.

3.3.1 Meter Information. If the ISO so requests, the Scheduling Coordinator shall provide in the format prescribed by Schedule 1 to this Agreement the required information with respect to the meters for all Scheduling Coordinator Metered Entities it represents including the reference to specific distribution loss factors or methodology it proposes to use as determined by the relevant UDC and approved by the relevant Local Regulatory Authority. The Scheduling Coordinator must

immediately notify the ISO of any changes to the information provided to the ISO in accordance with this Section 3.3.1 and provide the ISO with any information in relation to such change as reasonably requested by the ISO. Any amendments or additions to Schedule 1 shall not constitute an amendment to this Agreement.

3.3.2 Assistance and Cooperation of Scheduling Coordinator. The Scheduling Coordinator shall ensure that the ISO shall, upon reasonable notice, have access to the entire Metering Facilities of the Scheduling Coordinator Metered Entities that it represents from the meter data server to the Metering Facilities in order to inspect, test or otherwise audit those Metering Facilities.

3.3.3 Profiled and Cumulative Meter Data. The Scheduling Coordinator shall provide the ISO with any applicable load profile for each Scheduling Coordinator Metered Entity that it represents that is load profiled in accordance with the ISO Tariff. The Scheduling Coordinator shall provide a copy of the load profile applicable to each Scheduling Coordinator Metered Entity (if any) that it represents which shall be set forth in Schedule 2 to this Agreement. The Scheduling Coordinator must immediately notify the ISO of any changes to the load profiles referred to in Schedule 2 to this Agreement and provide the ISO with a copy of the new or amended load profile. Such change to Schedule 2 shall not constitute an amendment to this Agreement.

3.3.4 Security and Validation Procedures. The Scheduling Coordinator shall apply to the Meter Data of the Scheduling Coordinator Metered Entities that it represents, the security and validation procedures prescribed by the relevant Local Regulatory Authority. If the relevant Local Regulatory Authority has not prescribed any such procedures, the Scheduling Coordinator shall apply the procedures set forth in the ISO Tariff. Meter Data submitted by an Scheduling Coordinator for Scheduling Coordinator Metered Entities shall conform to these standards unless the ISO has, at its discretion, exempted the Scheduling Coordinator from these standards.

3.4 Obligations and Rights of the ISO.

3.4.1 Exemptions Granted by ISO. Any exemptions provided for under the ISO Tariff that are granted by the ISO shall be set forth in Schedule 3 to this Agreement. Any amendment or addition to Schedule 3 shall not constitute an amendment to this Agreement.

3.4.2 ISO as Third-Party Beneficiary. The ISO shall be a third-party beneficiary to the agreements between the Scheduling Coordinator and Scheduling Coordinator Metered Entities that the Scheduling Coordinator represents. Such agreements shall grant the ISO access to any relevant information, records and facilities of the Scheduling Coordinator Metered Entity as needed for the ISO to fulfill its obligations under this Agreement and the ISO Tariff.

ARTICLE IV

PENALTIES & SANCTIONS

4.1 Penalties. If the Scheduling Coordinator provides inaccurate or incorrect Settlement Quality Meter Data or fraudulent Meter Data to the ISO, the ISO shall be entitled to impose penalties and sanctions, including but not limited to suspension of trading rights following 14 days written notice to the Scheduling Coordinator. Fraudulent Meter Data means any data provided to the ISO by the Scheduling Coordinator that the Scheduling Coordinator knows to be false, incorrect or incomplete at the time it provided it to the ISO. All penalties and sanctions shall be set forth in Schedule 4 Part

A. No penalties or sanctions, including the suspension of trading rights, 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 Scheduling Coordinator 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 Scheduling Coordinator. The ISO will provide notice to all Scheduling Coordinators of any filing of proposed penalties or sanctions with the FERC. The ISO shall notify the Scheduling Coordinator of those approved penalties within 14 days of their approval by the FERC.

- 4.2 Corrective Measures.** If the Scheduling Coordinator or any Scheduling Coordinator Metered Entity that it represents fails to meet or maintain the standards for Metering Facilities or comply with the audit or test procedures as set forth in the ISO Tariff, the ISO shall be permitted to take corrective measures. Details of the corrective measures and rights the ISO may exercise upon any failure by any entity to meet those standards for Metering Facilities or to comply with the audit or test procedures shall be set forth in Schedule 4 Part B.

ARTICLE V

ACCESS TO METER DATA

- 5.1 Third Parties.** Third parties that are authorized by the Scheduling Coordinator to access the Meter Data of a Scheduling Coordinator Metered Entity held by the ISO and that are entitled to such Meter Data shall be identified in Schedule 5 to this Agreement. The Scheduling Coordinator shall not provide a third party access to Meter Data of a Scheduling Coordinator Metered Entity unless the Scheduling Coordinator has permission from that Scheduling Coordinator Metered Entity to provide that access. The relevant UDCs and TOs shall be included in Schedule 5 provided that the Scheduling Coordinator Metered Entity has granted those UDCs and TOs access to its Meter Data. Any amendment or addition to Schedule 5 shall not constitute an amendment to this Agreement. The Scheduling Coordinator shall, on request by the Scheduling Coordinator Metered Entity, access the Meter Data held by the ISO relating to that Scheduling Coordinator Metered Entity and provide that Meter Data to the Scheduling Coordinator Metered Entity in a timely manner.

ARTICLE VI

COSTS

- 6.1 Certification, Inspection and Auditing of Meters.** The Scheduling Coordinator shall be responsible for all reasonable costs incurred by the ISO or an ISO Authorized Inspector in connection with them carrying out the certification, inspection, testing or auditing of the meters identified in Schedule 1 from which the Scheduling Coordinator provides Meter Data to the ISO. The ISO or ISO Authorized Inspector will furnish the Scheduling Coordinator, upon request, an itemized bill for such costs.

ARTICLE VII

DISPUTE RESOLUTION

- 7.1 Dispute Resolution.** The Parties shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. In the event any dispute is not settled, the Parties shall adhere to the ISO ADR Procedures set forth in Section 13 of the ISO Tariff, which is incorporated by reference, except that all reference in Section 13 of the ISO Tariff to Market Participants shall be read as a reference to the Scheduling Coordinator Metered Entity and references to the ISO Tariff shall be read as references to this Agreement.

ARTICLE VIII

REPRESENTATIONS AND WARRANTIES

- 8.1 Representations and Warranties.** Each Party represents and warrants that the execution, delivery and performance of this Agreement by it has been duly authorized by all necessary corporate and/or governmental actions, to the extent authorized by law.
- 8.2 Necessary Authority.** The Scheduling Coordinator represents and warrants that all of the entities which it identifies on Schedule 1 as Scheduling Coordinator Metered Entities that it represents have granted it all necessary authority to enable it to carry out its obligations under this Agreement and the ISO Tariff, and, subject to the execution and delivery by the ISO, this Agreement will be enforceable against the Scheduling Coordinator in accordance with its terms.
- 8.3 Meter Data Access.** The Scheduling Coordinator represents and warrants that all third parties referred to in Schedule 5 to this Agreement have been authorized by the relevant Scheduling Coordinator Metered Entity as having access to its Settlement Quality Meter Data.

ARTICLE IX

LIABILITY AND INDEMNIFICATION

- 9.1 Liability and Indemnification.** The provisions of Section 14 of the ISO Tariff will apply to liability arising under this Agreement except that all references in Section 14 of the ISO Tariff to Market Participants shall be read as references to the Scheduling Coordinator and references in the ISO Tariff shall be read as references to this Agreement.

ARTICLE X

UNCONTROLLABLE FORCES

- 10.1 Uncontrollable Forces.** Section 14 of the ISO Tariff shall be incorporated by reference into this Agreement except that all references in Section 14 of the ISO Tariff to Market Participants shall be read as references to the Scheduling Coordinator and all references to the ISO Tariff shall be read as references to this Agreement.

ARTICLE XI

MISCELLANEOUS

- 11.1 Assignments.** Either Party may assign or transfer any or all of its rights and/or obligations under this Agreement with the other Party's prior written consent in accordance with Section 22.2 of the ISO Tariff. Such consent shall not be unreasonably withheld. Any such transfer or assignment shall be conditioned upon the successor in interest accepting the rights and/or obligations under this Agreement as if said successor in interest was an original Party to this Agreement.
- 11.2 Notices.** Any notice, demand or request which may be given to or made upon either Party regarding this Agreement shall be made in accordance with the Scheduling Coordinator's Scheduling Coordinator Agreement and in accordance with Section 22.4 of the ISO Tariff. A Party must update the information in Schedule 6 as information changes. Such changes shall not constitute an amendment to this Agreement.
- 11.3 Waivers.** Any waiver at any time by either 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 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.
- 11.4 Governing Law and Forum.** This Agreement shall be deemed to be a contract made under and for all purposes shall be governed by and construed in accordance with the laws of the State of California, except its conflict of law provisions. The Scheduling Coordinator irrevocably consents that any legal action or proceeding arising under or relating to this Agreement to which the ISO ADR Procedures do not apply shall be brought in any of the following forums, as appropriate: any court of the State of California, any federal court of the United States of America located in the State of California or, where subject to its jurisdiction, before the Federal Energy Regulatory Commission.
- 11.5 Consistency with Federal Laws and Regulations.** This Agreement shall incorporate by reference Section 22.9 of the ISO Tariff as if the references to the ISO Tariff were referring to this Agreement.
- 11.6 Merger.** This Agreement constitutes the complete and final agreement of the Parties with respect to the subject matter hereto and supersedes all prior agreements, whether written or oral, with respect to such subject matter.

- 11.7 Severability.** If any term, covenant, or condition of this Agreement or the application or effect of any such term, covenant, or condition is held invalid as to any person, entity, or circumstance, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in force and effect to the maximum extent permitted by law, and all other terms, covenants, and conditions of this Agreement and their application shall not be affected thereby, but shall remain in force and effect and the Parties shall be relieved of their obligations only to the extent necessary to eliminate such regulatory or other determination unless a court or governmental agency of competent jurisdiction holds that such provisions are not separable from all other provisions of this Agreement.
- 11.8 Amendments.** This Agreement and the Schedules attached hereto may be amended from time to time by the mutual agreement of the Parties in writing. Amendments that are subject to FERC approval shall not take effect until FERC has accepted such amendments for filing and has made them effective. If the amendment does not require FERC approval, the amendment will be filed with FERC for information.
- 11.9 Counterparts.** This Agreement may be executed in one or more counterparts at different times, each of which shall be regarded as an original and all of which, taken together, shall constitute one and the same Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed on behalf of each by and through their authorized representatives as of the date hereinabove written.

California Independent System Operator Corporation

By: _____

Name: _____

Title: _____

Date: _____

Full legal name of SC

By: _____

Name: _____

Title: _____

Date: _____

SCHEDULE 1

METER INFORMATION

[Section 3.3.1]

Meter Number

Name of the Facility

Contact details for Scheduling Coordinator Metered Entity Representative

SCHEDULE 2

APPROVED LOAD PROFILE

[Section 3.3.3]

Attach details of each load profile used by the Scheduling Coordinator Metered Entities represented by the Scheduling Coordinator, the names of the Scheduling Coordinator Metered Entities that use each of those load profiles and the name of the Local Regulatory Authority that approved each of those load profiles.

SCHEDULE 3

EXEMPTIONS FROM METERING STANDARDS AND OTHER REQUIREMENTS

[Section 3.4.1]

Exemption

Attach variation with an explanation.

Name of the relevant Local Regulatory Authority which sets security and validation standards for the Scheduling Coordinator Metered Entity.

Other Exemptions

SCHEDULE 4

PART A

ISO IMPOSED PENALTIES AND SANCTIONS

[Section 4.1]

TO BE INSERTED UPON FERC APPROVAL

PART B

CORRECTIVE MEASURES

[Section 4.2]

TO BE DEVELOPED

SCHEDULE 5

ACCESS TO METER DATA

[Section 5.1]

List the third parties authorized by each Scheduling Coordinator Metered Entity represented by the Scheduling Coordinator to access that Scheduling Coordinator Metered Entities' Settlement Quality Meter Data.

SCHEDULE 6

NOTICE

[Section 11.2]

Name of Primary

Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email address: _____

Phone: _____

Fax: _____

Name of Alternative

Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email address: _____

Phone: _____

Fax: _____

ISO:

Name of Primary

Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email address: _____

Phone: _____

Fax: _____

Name of Alternative

Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email address: _____

Phone: _____

Fax: _____

ISO TARIFF APPENDIX B.8
Utility Distribution Company Operating Agreement

CALIFORNIA INDEPENDENT SYSTEM OPERATOR

AND

[UTILITY DISTRIBUTION COMPANY]

UTILITY DISTRIBUTION COMPANY OPERATING AGREEMENT

**UTILITY DISTRIBUTION COMPANY
OPERATING AGREEMENT**

THIS OPERATING AGREEMENT is dated this ____ day of _____, ____ and is entered into, by and between:

- (1) **[Full legal name of UDC]** having its registered and principal place of business located at **[Address]** (the "UDC");

and
- (2) **California Independent System Operator Corporation**, a California non-profit public benefit corporation having its principal place of business located in such place in the State of California as the ISO Governing Board may from time to time designate, initially 151 Blue Ravine Road, Folsom, California 95630 (the "ISO").

The UDC and the ISO are hereinafter referred to as the "Parties".

Whereas:

- A. The purpose of this Operating Agreement is to establish the rights and obligations of the UDC and the ISO with respect to the UDC's Interconnection with the ISO Controlled Grid and the UDC's cooperation and coordination with the ISO to aid the reliability and the operational control of the ISO Controlled Grid and the UDC's Distribution System.
- B. The UDC owns and operates a Distribution System within the ISO Control Area subject to the authority of a Local Regulatory Authority.
- C. The UDC wishes to transmit Energy and/or supply Ancillary Services to or from the ISO Controlled Grid under the terms and conditions set forth in the ISO Tariff. The UDC also wishes to support and be part of the coordinated response to System Emergencies and to System Reliability concerns relating to the ISO Controlled Grid.
- D. The ISO has certain statutory obligations under California law to maintain the reliability of the ISO Controlled Grid.
- E. This Operating Agreement obligates the UDC and the ISO to comply with the relevant sections of the ISO Tariff, the ISO Operating Procedures and the ISO Specifications.
- F. The UDC and the Participating TO with which it is interconnected intend to coordinate the planning and implementation of any expansions or modifications of the UDC's or Participating TO's systems that will affect their transmission interconnection, the ISO Controlled Grid or the transmission services to be required by the UDC.

NOW THEREFORE, in consideration of the mutual covenants set forth herein, **THE PARTIES AGREE** as follows:

ARTICLE I

DEFINITIONS AND INTERPRETATION

1.1 Master Definitions Supplement. Unless defined in Section 1.2 of this Operating Agreement, all terms and expressions used in this Operating Agreement shall have the same meaning as those contained in the Master Definitions Supplement to the ISO Tariff.

1.2 Special Definitions for this Operating Agreement. In this Operating Agreement, the following words and expressions shall have the meanings set opposite them:

“ISO Specifications” means those standards pertaining to the areas of operation listed in Article IV of this Operating Agreement, approved by the ISO to establish detailed technical performance and reliability parameters at the ISO Controlled Grid and UDC Interconnection, associated with the ISO Tariff, as those standards may be amended from time to time.

“ISO Operating Procedure” means those procedures pertaining to the areas of operation listed in Article IV of this Operating Agreement, created by the ISO to establish detailed operating practices at the ISO Controlled Grid and UDC Interconnection, associated with general provisions required in the ISO Tariff, as those standards may be amended from time to time.

“Underfrequency Load Shedding (UFLS)” means automatic Load Shedding, accomplished by the use of such devices as underfrequency relays, intended to arrest frequency decline and assure continued operation within anticipated islands.

1.3 Rules of Interpretation. The following rules of interpretation and conventions shall apply to this Operating Agreement:

- (a) if there is any inconsistency between this Operating Agreement and the ISO Tariff, the ISO Tariff will prevail to the extent of the inconsistency;
- (b) the singular shall include the plural and vice versa;
- (c) the masculine shall include the feminine and neutral and vice versa;
- (d) “includes” or “including” shall mean “including without limitation”;
- (e) references to a Section, Article or Schedule shall mean a Section, Article or a Schedule of this Operating Agreement, as the case may be, unless the context otherwise requires;
- (f) a reference in this Operating Agreement to a given agreement, instrument or the ISO Tariff shall be a reference to that agreement, instrument or the ISO Tariff as modified, amended, supplemented or restated through the date as of which such reference is made;
- (g) unless the context otherwise requires, references to any law shall be deemed references to such law as it may be amended, replaced or restated from time to time;

- (h) unless the context otherwise requires, any reference to a "person" includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization or other entity, in each case whether or not having separate legal personality;
- (i) unless the context otherwise requires, any reference to a Party includes a reference to its permitted successors and assigns;
- (j) any reference to a day, week, month or year is to a calendar day, week, month or year; and the captions and headings in this Operating Agreement are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Operating Agreement.

ARTICLE II

TERM AND TERMINATION

- 2.1 Effective Date.** This Operating Agreement shall be effective as of the later of the date it is executed by the Parties or the date accepted for filing and made effective by the FERC and shall remain in full force and effect until the earlier of the termination date, the termination of the TCA or such other date as the Parties shall mutually agree. With respect to any such termination, the ISO must file a timely notice of termination with FERC, and this Operating Agreement shall terminate upon acceptance by FERC of such a notice of termination.
- 2.2 Termination Date.** Either Party (the terminating Party) may terminate this Operating Agreement by giving written notice in the event that the other Party (the defaulting Party) commits any default under this Operating Agreement and/or the ISO Tariff which, if capable of being remedied, is not remedied within 30 days after the terminating Party has given the defaulting Party written notice of the default, unless excused by reason of Uncontrollable Forces under Article X of this Operating Agreement. With respect to any notice of termination given pursuant to this Section, the ISO must file a timely notice of termination with FERC. The filing of the notice of termination by the ISO will be considered timely if: (1) the request to file a notice of termination is made after the preconditions for termination have been met, and (2) the ISO files the notice of termination within 30 days of receipt of such request. This Operating Agreement shall terminate upon acceptance by FERC of such a notice of termination.
- 2.3 Termination Pursuant to the TCA.** If the UDC is a party to the Transmission Control Agreement ("TCA"), this Operating Agreement shall terminate upon the effective date of the UDC's withdrawal from the TCA in accordance with Section 3.3 of the TCA, provided, however, that first the ISO shall have filed a timely notice of termination with FERC and FERC shall have accepted such notice of termination. The filing of the notice of termination by the ISO will be considered timely if: (1) the request to file a notice of termination is made after the preconditions for termination have been met, and (2) the ISO files the notice of termination within 30 days of receipt of such request.

ARTICLE III

GENERAL TERMS AND CONDITIONS

- 3.1.1 Facilities Under ISO Operational Control.** Parties shall identify on Schedule 1 those facilities of the UDC that the Parties mutually agree will be placed under the ISO's operational control pursuant to the ISO Tariff. In the event that a Party invokes the dispute resolution provision identified in Section 7.1 of this Operating Agreement, such dispute shall be resolved based upon whether the ISO's control over such disputed facilities is essential to meeting the Applicable Reliability Criteria, as defined in the ISO Tariff. With respect to each facility identified in Schedule 1, the Parties shall negotiate the extent of the ISO's operational control in order to meet said standard.
- 3.1.2 Facilities Financed by Local Furnishing Bonds or Other Tax-Exempt Bonds.** This Section 3.1.2 applies only to facilities which are under the operational control of the ISO and are owned by a UDC with Local Furnishing Bonds or other tax-exempt bonds. Nothing in this Operating Agreement shall compel (and the ISO is not authorized to request) any UDC with Local Furnishing Bonds, or other tax-exempt bonds, to violate restrictions applicable to facilities which are part of a system that was financed in whole or part with Local Furnishing Bonds or other tax-exempt bonds. The UDC shall cooperate with and provide all necessary assistance to the ISO in developing specific schedules to be included in executed Operating Agreements with such UDC to meet the intent of Section 3.1.1 of this Operating Agreement.
- 3.2 Agreement Subject to ISO Tariff.** This Operating Agreement shall be subject to the provisions of the ISO Tariff which shall be deemed to be incorporated by reference herein, as the same may be changed or superseded from time to time pursuant to Sections 22.10 and 22.4.3 of the ISO Tariff. The Parties agree that they will comply with Section 4.4, and any other applicable provisions, of the ISO Tariff.
- 3.3 Operation of ISO Controlled Grid.** The ISO shall operate the ISO Controlled Grid in accordance with the ISO Tariff and the Transmission Control Agreement to which it is a party.
- 3.4.1 Compliance with ISO Specifications and ISO Operating Procedure.** The UDC will abide by and will perform all of the obligations under the ISO Specifications and the ISO Operating Procedure placed on UDCs in respect of all matters set forth therein as the same may be changed or superseded from time to time pursuant to the procedures set forth in Sections 22.10 and 22.4.3 of the ISO Tariff. In the event of any conflict or dispute over interpretation, the ISO Tariff shall, at all times, take precedence over the ISO Specifications and ISO Operating Procedure. The ISO shall not implement any reliability requirements, operating requirements or performance standards that would impose increased costs on the UDC without giving due consideration to whether the benefits of such requirements or standards are sufficient to justify such increased costs. In any proceeding concerning the cost recovery by the UDC of capital and operation and maintenance costs incurred to comply with ISO Specifications and Operating Procedure, the ISO shall, at the request of the UDC, provide specific information regarding the nature of, and need for, the ISO-imposed requirements or standards to enable the UDC to use this information in support of cost recovery through rates and tariffs.
- 3.4.2 Review of Specifications and Operating Procedure.** The ISO shall periodically review with the UDC the ISO Specifications and Operating Procedure and, through the Grid Reliability and

Operations Committee process, shall modify the specifications and/or Operating Procedure as necessary.

- 3.4.3 Periods When Compliance is Required.** While awaiting dispute resolution or regulatory review, the UDC shall not be required to comply with changes to the ISO Specifications and/or Operating Procedure, except where compliance is necessary in order to prevent or remedy an imminent System Emergency.
- 3.5 Scheduling Coordinator Certification.** The UDC shall ensure that any Scheduling Coordinator through which it schedules Energy and Ancillary Services to or from the ISO Controlled Grid is appropriately certified in accordance with Section 4.5.1 of the ISO Tariff in accordance with the list of Scheduling Coordinators established by the ISO on WEnet.
- 3.6 Single Point of Contact.** The ISO and the UDC shall each provide a single point of contact on a 24-hour, 7-day basis for the exchange of operational procedures and information. In the case of a UDC that is also a Participating TO, there may be only one single point of contact required and, in the reasonable discretion of the ISO, duplicative reporting requirements and functions may be waived. Details of requirements relating to and the identity of the initial points of contact are set forth in Schedule 2.
- 3.7 Delegated Operational Responsibilities.** The UDC undertakes to perform all operational responsibilities delegated to the UDC by the ISO in accordance with Section 4.4.1.2 of the ISO Tariff and described in Schedule 3.

ARTICLE IV

OPERATIONAL COORDINATION

The Parties will perform the operational coordination obligations and responsibilities assigned to them under the ISO Tariff, the ISO Operating Procedures, and the ISO Specifications. The obligations and responsibilities include:

4.1 Maintenance Coordination

4.1.1 Maintenance Coordination for Facilities under ISO Control. The UDC shall schedule with the ISO on an annual basis any maintenance Outages of the equipment included in Schedule 1 pursuant to Schedule 4 in compliance with the ISO Tariff and shall coordinate its Outage requirements with the Participating TO with which it is interconnected.

4.1.2 Maintenance Coordination for Other Facilities. With respect to other facilities which may affect the reliability of the UDC Interconnection, the UDC shall coordinate its Outage requirements with the Participating TO with which it is interconnected.

4.2 System Emergencies. The responsibilities of the Parties in relation to System Emergencies are stated in the ISO Tariff and in Schedule 5. The ISO shall adopt fair and non-discriminatory procedures among the UDCs to ensure that no UDC bears a disproportionate share of the ISO's Load Shedding program.

- 4.2.1 Underfrequency Load Shedding (UFLS).** The responsibilities of the Parties in relation to UFLS are stated in Sections 7.4 and 7.4.9 of the ISO Tariff, the ISO Operating Procedure, the ISO Specifications and in Schedule 6.
- 4.2.2 Other Automatic Load Shedding.** The responsibilities of the Parties in relation to automatic Load Shedding as a function of voltage and other parameters are stated in the ISO Operating Procedure, the ISO Specifications and in Schedule 7.
- 4.2.3 Manual Load Shedding.** The responsibilities of the Parties to direct and to accept direction for manual disconnection of Load, under EEP, Load curtailment programs or other emergency plans, are stated in Section 7 and Section 7.4.11.3 of the ISO Tariff, the ISO Operating Procedure, the ISO Specifications and in Schedule 8.
- 4.3 Electrical Emergency Plan (EEP).** The responsibilities of the Parties in relation to the EEP are stated in Section 7.4.6 of the ISO Tariff, the ISO Operating Procedure, the ISO Specifications and in Schedule 9.
- 4.4 Load Restoration.** The responsibilities of the Parties for restoring Load following a system disturbance are stated in Section 7.4.11.3 of the ISO Tariff, the ISO Operating Procedure, the ISO Specifications and in Schedule 10.
- 4.5 Records, Information and Reports.** The Parties are required to maintain such records, to share information, and to make such reports as are stated in Section 4.4.12, 4.4.6, and 4.4.8 of the ISO Tariff, the ISO Operating Procedure, the ISO Specifications, and in Schedule 11. Additionally, the Parties shall jointly perform a review following a major Outage as provided in Section 7.4.13.1 of the ISO Tariff.
- 4.6 Interconnection Operation Standards.** The ISO and UDC shall maintain stable established operating parameters and control power and reactive flow within standards stated in the ISO Specifications and in Schedule 12.
- 4.7 Critical Protective Systems.** The UDC shall (in accordance with Section 11.2 of this Operating Agreement) notify the ISO as soon as is reasonably practicable of any condition that it becomes aware of that may compromise the ISO Controlled Grid Critical Protective Systems in accordance with Section 4.4.3 of the ISO Tariff and Schedule 13.
- 4.8 UDC Distribution Systems.** The ISO shall (in accordance with Section 11.2 of this Operating Agreement) notify the UDC as soon as is reasonably practicable of any condition which the ISO becomes aware that may compromise the operation and reliability of the UDC Distribution System.

ARTICLE V

ACCESS TO FACILITIES

- 5.1 Access Rights.** Pursuant to Section 4.4.8.4 of the ISO Tariff and Schedule 14 of this Operating Agreement, the ISO and the UDC shall each have the right to install or to have installed equipment or other facilities, including metering equipment, on the electric utility property of the other necessary for the implementation of this Operating Agreement. The ISO's installation of equipment on the property of the UDC shall comply with Local Regulatory Authority regulations, except where

compliance with Local Regulatory Authority regulations would cause the ISO to violate the ISO Tariff, and with all relevant safety standards. In such case, the UDC and ISO will work together to resolve the conflict between the Local Regulatory Authority regulations and the ISO Tariff.

- 5.2 Meter Testing.** The UDC shall, at the request of the ISO and upon reasonable notice, provide access to its facilities necessary to permit the ISO or an ISO-approved meter inspector to perform such testing as necessary in accordance with Section 4.4.8.4 of the ISO Tariff and the procedures set forth in Schedule 14.
- 5.3 Emergency Access Rights.** Section 4.4.8.4.3 of the ISO Tariff shall govern the ISO's right to access the UDC's equipment or other facilities during a System Emergency or where access is needed in connection with an audit function. In a System Emergency, the UDC shall have a right of access to ISO equipment on UDC property and UDC equipment on ISO property without notice.

ARTICLE VI

COSTS

- 6.1 UDC Operating and Maintenance Costs.** The UDC shall be responsible for all costs incurred in connection with procuring, installing, operating and maintaining its facilities identified in Schedule 1 for the purpose of meeting its obligations under this Operating Agreement.
- 6.2 ISO Operating and Maintenance Costs.** The ISO shall be responsible for the procurement, installation, operation and maintenance costs of ISO equipment set out in Article V of this Operating Agreement installed on UDC property.

ARTICLE VII

DISPUTE RESOLUTION

- 7.1 Alternative Dispute Resolution.** The Parties shall make reasonable efforts to settle all disputes arising out of or in connection with this Operating Agreement. In the event any dispute is not settled, the Parties shall adhere to the ISO ADR Procedures set forth in Section 13 of the ISO Tariff, which is incorporated by reference, except that all reference in Section 13 of the ISO Tariff to Market Participants shall be read as a reference to the UDC and references to the ISO Tariff shall be read as references to this Operating Agreement.

ARTICLE VIII

REPRESENTATIONS AND WARRANTIES

- 8.1 Representations and Warranties.** Each Party represents and warrants that its execution, delivery and performance of this Operating Agreement has been duly authorized by all necessary corporate and/or governmental actions, to the extent authorized by law.

- 8.2 Necessary Approvals.** Each Party represents that all necessary approvals, permits, licenses, easements, right of way or access to install, own and operate its facilities subject to this Operating Agreement have been obtained prior to the effective date of this Operating Agreement.

ARTICLE IX

LIABILITY

- 9.1 Extent of Liability.** The provisions of Section 14 of the ISO Tariff will apply to liability arising under this Operating Agreement, except that all references in Section 14 of the ISO Tariff to Market Participants shall be read as references to the UDC and references to the ISO Tariff shall be read as references to this Operating Agreement.

ARTICLE X

UNCONTROLLABLE FORCES

- 10.1 Uncontrollable Forces Tariff Provisions.** Section 14 of the ISO Tariff shall be incorporated by reference into this Operating Agreement, except that all references in Section 14 of the ISO Tariff to Market Participants shall be read as a reference to the UDC and references to the ISO Tariff shall be read as references to this Operating Agreement.

ARTICLE XI

MISCELLANEOUS

- 11.1 Assignments.** Either Party may assign its obligations under this Operating Agreement, with the other Party's prior written consent, in accordance with Section 22.2 of the ISO Tariff, which is incorporated by reference into this Operating Agreement. Such consent shall not be unreasonably withheld.
- 11.2 Notices.** Any notice, demand or request which may be given to or made upon either Party regarding this Operating Agreement shall be made in accordance with Section 22.4 of the ISO Tariff, which is incorporated by reference, except that all reference in Section 22.4 to Market Participants shall be read as a reference to the UDC. A Party must update the information relating to its address as that information changes in accordance with Section 22.4 of the ISO Tariff. Such changes will not constitute an amendment to this Operating Agreement.
- 11.3 Waivers.** Any waiver at any time by either Party of its rights with respect to any default under this Operating Agreement, or with respect to any other matter arising in connection with this Operating Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or matter arising in connection with this Operating Agreement. Any delay short of the statutory period of limitations, in asserting or enforcing any right under this Operating Agreement, shall not constitute or be deemed a waiver of such right.

11.4 Governing Law and Forum. This Operating Agreement shall be deemed to be a contract made under and for all purposes shall be governed by and construed in accordance with the laws of the State of California except in its conflict of laws provisions. The Parties irrevocably consent that any legal action or proceeding arising under or in relation to this Operating Agreement to which the ISO ADR Procedures do not apply, shall be brought in any of the following forums, as appropriate: any court of the State of California, any federal court of the United States of America located in the State of California or, where subject to its jurisdiction, before the Federal Energy Regulatory Commission.

11.5 Consistency with Federal Laws and Regulations.

- (a) Nothing in this Operating Agreement shall compel any person or federal entity to: (1) violate federal statutes or regulations; or (2) in the case of a federal agency, to exceed its statutory authority, as defined by any applicable federal statutes, regulations, or orders lawfully promulgated thereunder. If any provision of this Operating Agreement is inconsistent with any obligation imposed on any person or federal entity by federal law or regulation to that extent, it shall be inapplicable to that person or federal entity. No person or federal entity shall incur any liability by failing to comply with this Operating Agreement that is inapplicable to it by reason of being inconsistent with any federal statutes, regulations, or orders lawfully promulgated thereunder; provided, however, that such person or federal entity shall use its best efforts to comply with the ISO Tariff to the extent that applicable federal laws, regulations, and orders lawfully promulgated thereunder permit it to do so.
- (b) If any provision of this Operating Agreement requiring any person or federal entity to give an indemnity or impose a sanction on any person is unenforceable against a federal entity, the ISO shall submit to the Secretary of Energy or other appropriate Departmental Secretary a report of any circumstances that would, but for this provision, have rendered a federal entity liable to indemnify any person or incur a sanction and may request the Secretary of Energy or other appropriate Departmental Secretary to take such steps as are necessary to give effect to any provisions of this Operating Agreement that are not enforceable against the federal entity.

11.6 Integration. This Operating Agreement constitutes the full agreement of the Parties with respect to the subject matter hereto and supercedes all prior agreements, whether written or oral, with respect to such subject matter.

11.7 Severability. If any term, covenant, or condition of this Operating Agreement or the application or effect of any such term, covenant, or condition is held invalid as to any person, entity, or circumstance, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in force and effect to the maximum extent permitted by law, and all other terms, covenants, and conditions of this Operating Agreement and their application shall not be affected thereby, but shall remain in force and effect and the Parties shall be relieved of their obligations only to the extent necessary to eliminate such regulatory or other determination unless a court or governmental agency of competent jurisdiction holds that such provisions are not separable from all other provisions of this Operating Agreement.

11.8 Penalties. Any penalties to be levied under this Operating Agreement shall be established in accordance with the ISO Tariff after consultation between the UDC and the ISO, and approval by

the FERC, and shall be set out in Schedule 15. No penalties or sanctions may be imposed under this Operating Agreement unless a Schedule providing for such penalties or sanctions has first been filed with and made effective by FERC. Nothing in this Operating Agreement, with the exception of the provisions relating to ADR, shall be construed as waiving the rights of the UDC 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 UDC.

11.9 Section Headings: Section headings provided in this Operating Agreement are for ease of reading and are not meant to interpret the text in each Section.

11.10 Amendments. This Operating Agreement and the Schedules attached hereto may be amended from time to time by the mutual agreement of the Parties in writing. Amendments that require FERC approval shall not take effect until FERC has accepted such amendments for filing and made them effective. If the amendment does not require FERC approval, the amendment will be filed with FERC for information.

11.11 Counterparts. This Operating Agreement may be executed in one or more counterparts at different times, each of which shall be regarded as an original and all of which, taken together, shall constitute one and the same Operating Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Operating Agreement to be duly executed on behalf of each by and through their authorized representatives as of the date hereinabove written.

California Independent System Operator Corporation

By: _____

Name: _____

Title: _____

Date: _____

Full Name of UDC

By: _____

Name: _____

Title: _____

Date: _____

SCHEDULE 1

FACILITIES UNDER ISO CONTROL

The UDC will supply a list of UDC facilities that are placed under the operational control of the ISO in Schedule 1.

There are no UDC facilities to be listed here at present.

SCHEDULE 2

OPERATIONAL CONTACT

ISO:

Transmission Dispatcher

(Folsom):

Transmission Dispatcher

(Alhambra):

Shift Supervisor:

Manager of Dispatch and

Security Coordination:

City/State/Zip Code

Other ISO Dispatch Operations Phones:

Generation Dispatcher

(Folsom)

Generation Dispatcher

(Alhambra)

Security Coordinator

UDC:

Name of Primary

Representative: _____

Name of Alternative

Representative: _____

Title: _____

Operations Shift Supervisor

Address: _____

City/State/Zip Code _____

Email address: _____

Phone: _____

Fax: _____

The information to be contained in this Schedule may be subject to additional filing due to subsequent revisions as these may be required from time to time.

SCHEDULE 3

DELEGATED OPERATIONAL RESPONSIBILITIES

Currently the ISO has not delegated any operational responsibilities to the UDC in accordance with Section 4.1.2 of the ISO Tariff. If such a delegation occurs, they will be identified in this Schedule 3.

The information to be contained in this Schedule may be subject to additional filing due to subsequent revisions as these may be required from time to time.

SCHEDULE 4

MAINTENANCE COORDINATION

By October 1st of each year, the UDC will exchange with the ISO a provisional planned outage program for all lines and equipment in Schedule 1. That document will be updated quarterly or as changes occur to the proposed schedule.

The ISO will approve all outages on equipment and lines transferred to ISO operational control.

Applications for scheduled work will be submitted to the ISO by _____'s Grid Operations group via means to be agreed to by both Parties. The UDC documents will record the details for all work and become the data base for reporting and recording outage information.

The information to be contained in this Schedule may be subject to additional filing due to subsequent revisions as these may be required from time to time.

SCHEDULE 5

SYSTEM EMERGENCIES

The ISO will notify the UDC's operational contact (Operations Shift Supervisor - Grid Control), as identified in Schedule 2, of the emergency, including information regarding the cause, nature, extent, and potential duration of the emergency. The Operations Shift Supervisor will add any relevant data and will notify Distribution Operations. Distribution Operations will make the appropriate notifications within the UDC organization. The Operations Shift Supervisor and Distribution Control Shift Supervisor will then take such actions as are appropriate for the emergency.

The UDC will make requests for information from the ISO regarding emergencies through the Operations Shift Supervisor, or the UDC Communication Coordinator may coordinate public information with the ISO Communication Coordinator.

The UDC is required to estimate service restoration by geographic areas, and will use its call center and the media to communicate with customers during service interruptions. The UDC is also required to communicate the same information to appropriate state and local governmental entities. For transmission system caused outages the Operations Shift Supervisor will notify Distribution Operations Control Center of any information related to the outage such as cause, nature, extent, potential duration and customers affected.

Distribution Control and Grid Control Center logs, Electric Switching Orders and Energy Management System temporal data base will be used in preparation of outage reviews. These documents are defined as the chronological record of the operation of the activities which occur with the portion of the electrical system assigned to that control center. The log shall contain all pertinent information, including orders received and transmitted, relay operations, messages, clearances, accidents, trouble reports, daily switching program, etc.

The UDC will retain records in accordance with its Corporate Standard Practice for six years.

The information to be contained in this Schedule may be subject to additional filing due to subsequent revisions as these may be required from time to time.

SCHEDULE 6

UNDERFREQUENCY LOAD SHEDDING

The objective of the Underfrequency Load Shedding (UFLS) program is to provide security and protection to the interconnected bulk power network by arresting frequency decay during periods of insufficient resources

This plan establishes Underfrequency Load Shedding objectives consistent with the load shedding policies of the Western Systems Coordinating Council, the North American Electric Reliability Council and the UDC. The UDC's load shedding program will be in accordance with the WSCC Off-nominal Frequency Report requirements.

The information to be contained in this Schedule may be subject to additional filing due to subsequent revisions as these may be required from time to time.

SCHEDULE 7

OTHER AUTOMATIC LOAD SHEDDING

In addition to underfrequency relay load reduction, any undervoltage relay protection that is utilized in the UDC will be identified in the Attachment to this Schedule 7.

The information to be contained in this Schedule may be subject to additional filing due to subsequent revisions as these may be required from time to time.

SCHEDULE 8

MANUAL LOAD SHEDDING

[Note: Schedule 8 will detail the criteria governing the implementation of manual Load Shedding and/or interruptible Loads, and will describe the UDC's means of effecting Load Shedding and the estimated associated MW values of various UDC Loads to be shed. For Load curtailment programs Schedule 8 will also contain the UDC's capabilities until October 1 and thereafter annually.]

The information to be contained in this Schedule may be subject to additional filing due to subsequent revisions as these may be required from time to time.

SCHEDULE 8A

ROTATING LOAD CURTAILMENT PROCEDURES

The information to be contained in this Schedule may be subject to additional filing due to subsequent revisions as these may be required from time to time.

SCHEDULE 8B

INTERRUPTIBLE LOAD

The information to be contained in this Schedule may be subject to additional filing due to subsequent revisions as these may be required from time to time.

SCHEDULE 9

ELECTRICAL EMERGENCY PLAN

The ISO Specifications will outline the basic criteria for the development, coordination, and implementation of the UDC EEP and the requirements for coordination with the ISO EEP. Schedule 9 will include the UDC EEP as coordinated with the ISO EEP.

The information to be contained in this Schedule may be subject to additional filing due to subsequent revisions as these may be required from time to time.

SCHEDULE 10

LOAD RESTORATION

The UDC will follow the procedures set forth below in this Schedule 10 in promoting orderly, coordinated restoration of electric systems after a major system disturbance has occurred which resulted in load shedding by frequency relays in California.

1. Immediately after load shedding by frequency relay has occurred in the UDC, the UDC will remain in contact with their respective Participating Transmission Owner (PTO) Area Control Center (ACC) until normal frequency has been restored throughout the ISO Control Area or the ISO Shift Supervisor has concluded that such full-time communications can be terminated. Emergency communications over the California ACC Hot-line will be under the direction of the ISO Shift Supervisor and the senior dispatcher present at the affected PTO ACC(s).
2. Manual load restoration will not normally be initiated until the California ACC Hot Line is attended. No load is to be manually restored unless directed by the ISO after the frequency has recovered and there is indication that the frequency can be maintained. The UDC will await direction from their respective PTO ACC who will be in contact with the ISO Shift Supervisor. The ISO Shift Supervisor will determine whether adequate generation resources are available on line to support the load to be restored.
3. Any UDC automatic load restoration will be consistent with the WSCC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan.
4. If the ISO cannot meet the WSCC and NERC Control Area Disturbance Control Standard or the Control Performance Standard post disturbance, no manual load restoration will be permitted. If the frequency is such that automatic load restoration occurs under these conditions, the UDC(s) which has restored load automatically will manually shed an equivalent amount of load to offset the load which was automatically restored.
5. Restoration of ties and off-site power supply to nuclear generating facilities should be given top priority. Manual load restoration will be deferred during periods of tie restoration. The UDC should be equipped and prepared to drop load manually when necessary to allow frequency recovery sufficient to re-establish ISO intra-area ties and ties between the ISO Control Area and outside systems. Where manual load shedding is required, the ISO shall make reasonable efforts to allocate the load shedding requirement equitably among the UDCs where load shedding will be beneficial.
6. The UDC will use its existing plans and priorities to restore load within the parameters given by the ISO, giving the appropriate priority to essential services such as military, public safety agencies, water treatment plants, sewage treatment plants, etc.

The information to be contained in this Schedule may be subject to additional filing due to subsequent revisions as these may be required from time to time.

SCHEDULE 11

RECORDS, INFORMATION, REPORTS

The ISO and UDC will jointly develop any necessary forms and procedures for collection, study and transmittal of system data, information, reports, and forecasts.

The information to be contained in this Schedule may be subject to additional filing due to subsequent revisions as these may be required from time to time.

SCHEDULE 12

INTERCONNECTION OPERATION STANDARDS

The ISO and UDC shall jointly maintain stable operating parameters and control power and reactive flow in accordance with the ISO Tariff and the following Interconnection Operation Standards.

UDC Responsibilities

- 1.0 The UDC shall operate its facilities at each point of interconnection with the ISO Controlled Grid in such manner as to avoid any material or adverse impact on the ISO Controlled Grid. In accordance with this performance goal, the UDC shall:
 - 1.1 Operate its facilities at each point of interconnection with the ISO Controlled Grid within established operating parameters including normal ratings, emergency ratings, voltage limits, and balance of load between electrical phases.
 - 1.2 Maintain primary and backup protective systems such that faults on UDC facilities will be cleared with minimal impact on the ISO Controlled Grid.
 - 1.3 Maintain load power factor at each point of interconnection with the ISO Controlled Grid as close as possible to unity power factor and pursuant to Section 8.2.3.4 of the ISO Tariff.

ISO Responsibilities

- 2.0 The ISO shall operate the ISO Controlled Grid at each point of interconnection with the UDC in such manner as to avoid any material or adverse impact on the UDC facilities. In accordance with this performance goal, the ISO shall:
 - 2.1 Participate with the UDC and TO in the development of joint power quality performance standards and jointly maintain compliance with such standards.
 - 2.2 Observe UDC grid voltage limits specified in Attachment 7 including requirements for reduced voltage on ISO Controlled Grid facilities which apply during heavy fog (or other unusual operating conditions) as needed to minimize the risk of insulator flashover.
 - 2.3 Approve transmission owner maintenance requests in a timely manner, and shall not unreasonably withhold approval of TO requests for authorization to perform energized insulator washing work or to take planned Outages needed to replace or insul-grease insulators.
 - 2.4 Support UDC investigation of power quality incidents, and provide related data to the UDC in a timely manner.

2.5 Support installation of apparatus on the ISO Controlled Grid to improve power quality, and take all reasonable measures to investigate and mitigate power quality concerns caused by actions or events in neighboring systems or control areas.

2.6 Maintain load power factor at each UDC Interconnection as close as possible to unity power factor and pursuant to Section 8.2.3.4 of the ISO Tariff.

The information to be contained in this Schedule may be subject to additional filing due to subsequent revisions as these may be required from time to time.

SCHEDULE 13

CRITICAL PROTECTION SYSTEMS

Distribution protective relay schemes affecting the ISO Controlled Grid are those associated with transformers that would trip transmission breakers and/or busses at UDC Interconnection point when activated. These would include any of the following:

1. High Side Overcurrent Relays
2. Differential Overcurrent Relays
3. Sudden Pressure Relays
4. Low Oil Relays
5. Neutral Ground Overcurrent Relays
6. On fuse protected transformers, it would be the high-side fuses.

The information to be contained in this Schedule may be subject to additional filing due to subsequent revisions as these may be required from time to time.

SCHEDULE 14

RIGHTS OF ACCESS TO FACILITIES

14.1 Equipment Installation. In order to give effect to this Operating Agreement, a Party that requires to use particular equipment (the equipment owner) may require installation of such equipment on property owned by the other Party (the property owner), provided that the equipment is necessary to meet the equipment owner's service obligations and that the equipment shall not have a negative impact on the reliability of the service provided, nor prevent the property owner from performing its own obligations or exercising its rights under this Operating Agreement.

14.1.1 Free Access. The property owner shall grant to the equipment owner free of charge reasonable installation rights and rights of access to accommodate equipment inspection, maintenance, repair, upgrading, or removal for the purposes of this Operating Agreement, subject to the property owner's reasonable safety, operational, and future expansion needs.

14.1.2 Notice. The equipment owner shall provide reasonable notice to the property owner when requesting access for site assessment, equipment installation, or other relevant purposes. Such access shall not be provided unless the parties mutually agree to the date, time, and purpose of each access. Agreement on the terms of the access shall not be unreasonably withheld or delayed.

14.1.3 Removal of Installed Equipment. Following reasonable notice, the equipment owner shall be required, at its own expense, to remove or relocate equipment, at the request of the property owner, provided that the equipment owner shall not be required to do so if it would have a negative impact on the reliability of the service provided, or be prevented from performing its own obligations or exercising its rights under this Operating Agreement.

14.1.4 Costs. The equipment owner shall repair at its own expense any property damage it causes in exercising its rights and shall reimburse the property owner for any other reasonable costs that it may be required to incur to accommodate the equipment owner's exercise of its rights under this Section 14.1.

14.2 Rights to Assets. The Parties shall not interfere with each other's assets, without prior written agreement.

14.3 Inspection of Facilities. In order to meet their respective obligations under this Operating Agreement, each Party may view or inspect facilities owned by the other Party. Provided that reasonable notice is given, a Party shall not unreasonably deny access to relevant facilities for viewing or inspection by the requesting Party.

14.4 Access During Emergencies. Either Party shall have rights of access, without prior notice, to the other Party's equipment as necessary during times of a System Emergency.

SCHEDULE 15

PENALTIES AND SANCTIONS

Intentionally left blank, initially, in accordance with Section 11.7

The information to be contained in this Schedule will be filed when complete following current revisions and development and may thereafter be subject to additional filing due to subsequent revisions as these may be required from time to time.

ISO TARIFF APPENDIX B.9
Dynamic Scheduling Host Control Area Operating Agreement

CALIFORNIA INDEPENDENT SYSTEM OPERATOR

AND

[CONTROL AREA]

DYNAMIC SCHEDULING HOST CONTROL AREA OPERATING AGREEMENT

**DYNAMIC SCHEDULING HOST CONTROL AREA
OPERATING AGREEMENT**

THIS DYNAMIC SCHEDULING HOST CONTROL AREA OPERATING AGREEMENT (“AGREEMENT”) is established this ____ day of _____, ____ and is accepted by and between:

[Full legal name] (“Host Control Area”), having its registered and principal executive office at [address],
and

California Independent System Operator Corporation (“ISO”), a California nonprofit public benefit corporation having a principal executive office located at such place in the State of California as the ISO Governing Board may from time to time designate, initially 151 Blue Ravine Road, Folsom, California 95630.

The Host Control Area and the ISO are hereinafter referred to as the “Parties”.

Whereas:

- A.** The Parties named above operate Control Areas.
- B.** The Parties wish to coordinate operation of dynamic scheduling functionality to satisfy North American Electric Reliability Council (“NERC”) policies, Western Electricity Coordinating Council (“WECC”) Minimum Operating Reliability Criteria (“MORC”), and Good Utility Practice.
- C.** The Host Control Area does not have an Interconnected Control Area Operating Agreement (“ICAOA”) with the ISO and desires to implement an agreement to facilitate dynamic scheduling from System Resources in its Control Area to the ISO Control Area without an ICAOA.
- D.** The Parties wish to enter into this Agreement to establish the terms and conditions for the operation of the dynamic scheduling functionality from Host Control Area’s Control Area to the ISO Control Area.
- E.** The ISO has certain statutory obligations under California law to maintain power system reliability.

NOW THEREFORE, in consideration of the mutual covenants set forth herein, **THE PARTIES AGREE** as follows:

1. Term and Termination

1.1 Effective Date

This Agreement shall be effective as of the date set forth above, unless this Agreement is accepted for filing and made effective by the Federal Energy Regulatory Commission (“FERC”) on some other date, if FERC filing is required, and shall continue in effect until terminated.

1.2 Termination

This Agreement may be terminated by either Party upon thirty (30) days written notice to the other Party or upon mutual consent of both Parties. For entities subject to FERC jurisdiction, termination will be effective upon acceptance by FERC of notice of termination, if this Agreement has been filed with FERC, or thirty (30) days after the date of the notice of default, if terminated in accordance with the requirements of FERC Order No. 2001 and related FERC orders. The ISO shall timely file any required notice of termination with FERC. The filing of the notice of termination by the ISO will be considered timely if: (1) the request to file a notice of termination is made after the preconditions for termination have been met, and (2) the ISO files the notice of termination within sixty (60) days after issuance of the notice of default.

2. Definitions

2.1 WECC Definitions

Except as defined below, terms and expressions used in this Agreement shall have the same meanings as those contained in the WECC MORC Definitions.

2.2 Specific Definitions

2.2.1 Good Utility Practice: Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry in the WECC region 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.

2.2.2 ISO Tariff: ISO Operating Agreement, Protocols, and Tariff as amended from time to time, together with any appendices or attachments thereto.

2.2.3 Point of Contact: A person or entity having the authority to receive and act upon scheduling or dispatch communications from the other Control Area operator and available through a communications device mutually agreed upon on a 24-hour, 7-day basis.

2.2.4 Scheduling Coordinator: An entity certified by the ISO for the purposes of undertaking the functions of: submitting schedules for energy, generation, transmission losses, and ancillary services; coordinating generation; tracking, billing, and settling trades with other Scheduling Coordinators; submitting forecast information; paying the ISO's charges; and ensuring compliance with ISO protocols.

2.2.5 Standards: The ISO's "*Standards for Dynamic Imports of Energy, Supplemental Energy, and Energy Associated with Non-Regulation Ancillary Services*," which document is posted on the ISO internet home page (www.caiso.com).

2.2.6 System Resource: "System Resource" is defined in the ISO Tariff and, in the context of this Agreement, may include combinations of resources as described in the Standards.

3. General

3.1 Purpose

This Agreement sets forth the requirements that must be satisfied by the Host Control Area should it elect to support Scheduling Coordinators' requests for implementation of a dynamic scheduling functionality and delivery of energy, supplemental energy, and energy associated with ancillary services (except regulation service) into the ISO Control Area. The requirements encompass technical (energy management system ("EMS")/ automatic generation control ("AGC") and communications), interchange scheduling, telemetry, and aspects of Control Area operations.

3.2 NERC/WECC Operating Standards Observed

Nothing in this Agreement is intended to change, supersede, or alter either Party's obligations to abide by NERC standards and policies and WECC criteria.

3.3 Applicable Standards

This Agreement incorporates, by reference, the ISO's Standards.

3.4 Communication

The ISO and the Host Control Area shall each operate and maintain a 24-hour, 7-day control center with real time scheduling and control functions. Appropriate control center staff will be provided by each Party who shall be responsible for operational communications and who shall have sufficient authority to commit and bind that Party. The ISO and the Host Control Area shall jointly develop communication procedures necessary to support scheduling and dispatch functions. The Points of Contact and the procedures for insuring reliable communication are identified in Schedule 1.

4. Telecommunications Requirements

The ISO and Host Control Area shall establish and maintain real time, redundant, diversely routed, communications links between the ISO EMS and the Host Control Area EMS, with the primary link utilizing the standard inter-control center communications protocol ("ICCP") in accordance with the Standards for the dynamically scheduled System Resources listed in Schedule 2.

5. Telemetry

For each operating hour for which a System Resource is scheduled to deliver energy, supplemental energy, and/or energy associated with any of the non-regulating ancillary services to the ISO Control Area, the Host Control Area shall provide, via the ICCP communication links to the ISO EMS, the data for each System Resource, as set forth in the Standards.

6. Interchange Scheduling Requirements

6.1 Dynamic Scheduling

The Host Control Area shall support Scheduling Coordinators' requests to arrange dynamic interchange schedules for the delivery of energy to the ISO Control Area, reflecting the System

Resource's instantaneous energy production or allocation level and taking into account available transmission capacity.

6.2 Treatment of Area Control Error ("ACE")

The Host Control Area shall instantaneously compensate its AGC for the System Resource's energy output that is generated or allocated for establishing the dynamic schedule to the ISO such that the System Resource energy production or allocation changes have an equal in magnitude and opposite in sign effect on the Host Control Area's ACE.

6.2 Integration of Dynamic Scheduling

For each operating hour during which energy was dynamically scheduled for delivery to the ISO Control Area, the Host Control Area shall compute an integrated amount of interchange based on the System Resource's integrated energy production, by integrating the instantaneous System Resource production levels. Such integrated MWH value shall be agreed to hourly by the real time schedulers.

6.3 Delivery of Megawatts ("MW")

The Host Control Area shall not be obligated to make up any difference between the dynamic energy schedule and the MW being generated or allocated by the System Resource.

6.4 Access to Information

The Parties agree to exchange information related to telemetry sent and received with respect to the delivery of energy (i) at the request of the other Party for purposes of after-the-fact interchange accounting or (ii) on demand for any other purpose.

7. Other Host Control Area Responsibilities

7.1 Operational Jurisdiction

The Host Control Area will have, at a minimum, the level of operational jurisdiction over the System Resource and the associated dynamic schedule that NERC and WECC vest in Host Control Areas.

7.2 E-Tagging

The Host Control Area must support associated e-tagging as described in the Standards and deemed to be consistent with NERC and/or WECC requirements.

7.3 Real-Time Adjustments

The Host Control Area must have a means to manually override and/or otherwise adjust the dynamic signal in real time, if needed.

7.4 Coordination with Other Control Areas

The Host Control Area must provide in real time the instantaneous value of each dynamic schedule to every intermediary Control Area through whose systems such dynamic schedule may be implemented to the ISO.

8. Other

8.1 Losses

The ISO shall not be responsible for transmission losses caused by transmitting energy dynamically within or across the Host Control Area for delivery to the ISO.

8.2 Certification

Only ISO-certified System Resource/Host Control Area arrangements will be allowed to bid or self provide ancillary services in the ISO's ancillary services market through an ISO-certified Scheduling Coordinator.

8.3 No Guarantee of Award

Certification of a System Resource/Host Control Area arrangement allows for bidding of supplemental energy and/or certain ancillary services into the ISO market; it does not, however, guarantee selection of such bid.

8.4 Performance Assessment

The ISO will monitor and measure dynamically imported ancillary services, whether bid or self-provided, against the performance benchmarks described in the Standards.

8.5 Description of System Resources

Each dynamically scheduled System Resource permitted pursuant to this Agreement is described in Schedule 2.

9. Notifications

The ISO and the Host Control Area shall jointly develop methods for coordinating the notification of all affected scheduling entities within their respective Control Areas regarding schedule changes in emergency or curtailment conditions.

10 Liability

10.1 Uncontrollable Forces

An Uncontrollable Force means 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 a control area operator which could not be avoided through the exercise of Good Utility Practice.

Neither the ISO nor the Host Control Area will be considered in default of any obligation under this Agreement or liable to the other for direct, indirect, and consequential damages if prevented from fulfilling that obligation due to the occurrence of an Uncontrollable Force.

In the event of the occurrence of an Uncontrollable Force, which prevents either the ISO or the Host Control Area from performing any obligations under this Agreement, the affected entity shall not be entitled to suspend performance of its obligations in any greater scope or for any longer duration than is required by the Uncontrollable Force. The ISO and the Host Control Area shall each use its best efforts to mitigate the effects of such Uncontrollable Force, remedy its inability to perform, and resume full performance of its obligations hereunder.

10.2 Liability To Third Parties

Except as otherwise expressly provided herein, nothing in this Agreement shall be construed or deemed to confer any right or benefit on, or to create any duty to, or standard of care with reference to any third party, or any liability or obligation, contractual or otherwise, on the part of ISO or the Host Control Area.

10.3 Liability Between the Parties

The Parties' duties and standard of care with respect to each other, and the benefits and rights conferred on each other, shall be no greater than as explicitly stated herein. Neither Party, its directors, officers, employees, or agents, shall be liable to the other Party for any loss, damage, claim, cost, charge, or expense, whether direct, indirect, or consequential, arising from the Party's performance or nonperformance under this Agreement, except for a Party's gross negligence, or willful misconduct.

11 Miscellaneous

11.1 Assignments

Either Party to this Agreement may assign its obligations under this Agreement, with the other Party's prior written consent. Such consent shall not be unreasonably withheld.

Obligations and liabilities under this Agreement shall be binding on the successors and assigns of the Parties. No assignment of this Agreement shall relieve the assigning Party from any obligation or liability under this Agreement arising or accruing prior to the date of assignment.

11.2 Notices

Any notice, demand, or request which may be given to or made upon either Party regarding this Agreement shall be made in writing and shall be deemed properly served, given, or made: (a) upon delivery if delivered in person, (b) five (5) days after deposit in the mail if sent by first class United States mail, postage prepaid, (c) upon receipt of confirmation by return facsimile if sent by facsimile, or (d) upon delivery if delivered by prepaid commercial courier service. A Party must update the information in Schedule 3 relating to its address as that information changes. Such changes shall not constitute an amendment to this Agreement.

11.3 Waivers

Any waiver at any time by either 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 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.

11.4 Governing Law and Forum

Subject to ICAA 11.5, this Agreement shall be deemed to be a contract made under and for all purposes shall be governed by and construed in accordance with the laws of the State of California. The Parties irrevocably consent that any legal action or proceeding arising under or relating to this Agreement shall be brought in any of the following forums, as appropriate: a court of the State of California or any federal court of the United States of America located in the State of California or, where subject to its jurisdiction, before the Federal Energy Regulatory Commission. No provision of this Agreement shall be deemed to waive the right of any Party to protest, or challenge in any manner, whether this Agreement, or any action or proceeding arising under or relating to this Agreement, is subject to the jurisdiction of the Federal Energy Regulatory Commission.

11.5 Consistency with Federal Laws and Regulations

(a) Nothing in this Agreement shall compel any person or federal entity to: (1) violate federal statutes or regulations; or (2) in the case of a federal agency, to exceed its statutory authority, as defined by any applicable federal statutes, regulations, or orders lawfully promulgated thereunder. If any provision of this Agreement is inconsistent with any obligation imposed on any person or federal entity by federal law or regulation to that extent, it shall be inapplicable to that person or federal entity. No person or federal entity shall incur any liability by failing to comply with any provision of this Agreement that is inapplicable to it by reason of being inconsistent with any federal statutes, regulations, or orders lawfully promulgated thereunder; provided, however, that such person or federal entity shall use its best efforts to comply with the ISO Tariff to the extent that applicable federal laws, regulations, and orders lawfully promulgated thereunder permit it to do so.

(b) If any provision of this Agreement requiring any person or federal entity to give an indemnity or impose a sanction on any person is unenforceable against a federal entity, the ISO shall submit to the Secretary of Energy or other appropriate Departmental Secretary a report of any circumstances that would, but for this provision, have rendered a federal entity liable to indemnify any person or incur a sanction and may request the Secretary of Energy or other appropriate Departmental Secretary to take such steps as are necessary to give effect to any provisions of this Agreement that are not enforceable against the federal entity.

11.6 Severability

If any term, covenant, or condition of this Agreement or the application or effect of any such term, covenant, or condition is held invalid as to any person, entity, or circumstance, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in force and effect to the maximum extent permitted by law, and all other terms, covenants, and

conditions of this Agreement and their application shall not be affected thereby, but shall remain in force and effect and the parties shall be relieved of their obligations only to the extent necessary to eliminate such regulatory or other determination unless a court or governmental agency of competent jurisdiction holds that such provisions are not separable from all other provisions of this Agreement.

11.7 Section Headings

Section headings provided in this Agreement are for ease of reading and are not meant to interpret the text in each Section.

11.8 Amendments

This Agreement and the Schedules attached hereto may be amended from time to time by the mutual agreement of the Parties in writing. Amendments that are subject to FERC approval shall not take effect until FERC has accepted such amendments for filing and has made them effective. If the amendment does not require FERC approval, the amendment will be filed with FERC for information. Nothing contained herein shall be construed as affecting in any way the right of the ISO or the Host Control Area to unilaterally make application to FERC for a change in the rates, terms and conditions of this Agreement under Section 205 of the FPA and pursuant to FERC's rules and regulations promulgated thereunder.

11.9 Counterparts

This Agreement may be executed in one or more counterparts at different times, each of which shall be regarded as an original and all of which, taken together, shall constitute one and the same Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed on behalf of each by and through their authorized representatives as of the date first written above.

California Independent System Operator Corporation

By: _____

Name: _____

Title: _____

Date: _____

[Full legal name of Host Control Area]

By: _____

Name: _____

Title: _____

Date: _____

SCHEDULE 1

POINTS OF CONTACT
[Section 3.4]

OPERATIONAL CONTACT

ISO:

Transmission Dispatcher
(Folsom-Primary): _____

Transmission Dispatcher
(Alhambra-Backup): _____

Generation Dispatcher
(Folsom-Primary): _____

Generation Dispatcher
(Alhambra-Backup): _____

Real Time Scheduler
(Folsom): _____

Real Time Scheduler
(Alhambra): _____

Pre Scheduler: _____

Shift Manager: _____

Control Room Fax: _____

Outage Coordination:
Fax: _____

Director of Grid Operations: _____

WECC Reliability Coordinator: _____

Address: California ISO
151 Blue Ravine Road
P.O. Box 639014
Folsom, CA 95763-9014

OPERATIONAL CONTACT

Host Control Area:

Transmission Dispatcher
(Primary):

Transmission Dispatcher
(Backup):

Generation Dispatcher
(Primary):

Generation Dispatcher
(Backup):

Real Time Scheduler:

Dispatch Supervisor:

Outage Coordination:

Fax:

Chief Dispatcher:

Address:

SCHEDULE 2

DESCRIPTION OF DYNAMICALLY SCHEDULED SYSTEM RESOURCES
[Section 4]

SCHEDULE 3

NOTICES
[Section 11.2]

Host Control Area

Name of Primary

Representative: _____

Title: _____

Company: _____

Address: _____

City/State/Zip Code _____

Email Address: _____

Phone: _____

Fax No: _____

Name of Alternative

Representative: _____

Title: _____

Company: _____

Address: _____

City/State/Zip Code _____

Email Address: _____

Phone: _____

Fax No: _____

ISO

Name of Primary Representative: _____

Title: _____

Address: _____

City/State/Zip Code _____

Email Address: _____

Phone: _____

Fax No: _____

Name of Alternative Representative: _____

Title: _____

Address: _____

City/State/Zip Code _____

Email Address: _____

Phone: _____

Fax No: _____

ISO TARIFF APPENDIX B.10
Small Utility Distribution Company Operating Agreement

CALIFORNIA INDEPENDENT SYSTEM OPERATOR

AND

[SMALL UTILITY DISTRIBUTION COMPANY]

SMALL UTILITY DISTRIBUTION COMPANY OPERATING AGREEMENT

**SMALL UTILITY DISTRIBUTION COMPANY
OPERATING AGREEMENT**

THIS OPERATING AGREEMENT is dated this ____ day of _____, ____ and is entered into, by and between:

- (1) **[Full legal name of SUDC]**, having its registered and principal place of business located at **[Address]** (the "SUDC");
and
- (2) **California Independent System Operator Corporation**, a California non-profit public benefit corporation having its principal place of business located in such place in the State of California as the ISO Governing Board may from time to time designate, initially 151 Blue Ravine Road, Folsom, California 95630 (the "ISO").

The SUDC and the ISO are hereinafter referred to individually as "Party" and collectively as "Parties".

Whereas:

- A. The purpose of this Operating Agreement is to establish the rights and obligations of the SUDC and the ISO with respect to the SUDC's Facilities interconnected with the ISO Controlled Grid and the SUDC's cooperation and coordination with the ISO regarding reliability and the operational control of the ISO Controlled Grid and the SUDC's Distribution System.
- B. The SUDC owns and operates a small Distribution System within the ISO Control Area subject to the authority of a Local Regulatory Authority.
- C. The SUDC wishes to receive and transmit Energy and/or Ancillary Services to and/or from the ISO Controlled Grid under the terms and conditions set forth in the ISO Tariff.
- D. The ISO has certain statutory obligations under California law to maintain the reliability of the ISO Controlled Grid.
- E. The Parties recognize that while a single SUDC has little or no ability to materially, adversely affect reliability of the ISO Controlled Grid or the ISO Control Area, the SUDC agrees to support and be part of the coordinated response to System Emergencies and to reliability concerns relating to the ISO Control Area as set forth in this Operating Agreement.
- F. This Operating Agreement obligates the SUDC to comply with the sections of the ISO Tariff, the ISO Operating Procedures and the ISO Specifications specified in this Operating Agreement.

NOW THEREFORE, in consideration of the mutual covenants set forth herein, **THE PARTIES AGREE** as follows:

**ARTICLE I
DEFINITIONS AND INTERPRETATION**

- 1.1 Master Definitions Supplement.** Unless defined in Section 1.2 of this Operating Agreement, all defined terms and expressions used in this Operating Agreement shall have the same meaning as those contained in the Master Definitions Supplement to the ISO Tariff.

1.2 Special Definitions for this Operating Agreement. In this Operating Agreement, the following words and expressions shall have the meanings set opposite them:

“ISO Specifications” means those standards pertaining to the areas of operation listed in Article IV of this Operating Agreement and listed in Schedule 6, approved by the ISO to establish detailed technical performance and reliability parameters at the ISO Controlled Grid and SUDC Interconnection, associated with the ISO Tariff, as those standards may be amended from time to time.

“ISO Operating Procedures” means those procedures pertaining to the areas of operation listed in Article IV of this Operating Agreement and listed in Schedule 9, created by the ISO to establish detailed operating procedures at the ISO Controlled Grid and SUDC Interconnection, associated with general provisions required in the ISO Tariff, as those standards may be amended from time to time.

“SUDC Facilities” shall have the meaning accorded to such term as provided in Section 3.2 of this Operating Agreement.

1.3 Rules of Interpretation. The following rules of interpretation and conventions shall apply to this Operating Agreement:

- (a) if there is any inconsistency between this Operating Agreement and the ISO Tariff, the ISO Tariff will prevail to the extent of the inconsistency;
- (b) the singular shall include the plural and vice versa;
- (c) the masculine shall include the feminine and neutral and vice versa;
- (d) “includes” or “including” shall mean “including without limitation”;
- (e) references to a Section, Article or Schedule shall mean a Section, Article or a Schedule of this Operating Agreement, as the case may be, unless the context otherwise requires;
- (f) a reference in this Operating Agreement to a given agreement, instrument or the ISO Tariff shall be a reference to that agreement, instrument or the ISO Tariff as modified, amended, supplemented or restated through the date as of which such reference is made;
- (g) unless the context otherwise requires, references to any law shall be deemed references to such law as it may be amended, replaced or restated from time to time;
- (h) unless the context otherwise requires, any reference to a “person” includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization or other entity, in each case whether or not having separate legal personality;
- (i) unless the context otherwise requires, any reference to a Party includes a reference to its permitted successors and assigns;
- (j) any reference to a day, week, month or year is to a calendar day, week, month or year; and the captions and headings in this Operating Agreement are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Operating Agreement.

ARTICLE II TERM AND TERMINATION

- 2.1 Effective Date.** This Operating Agreement shall be effective as of the date it is accepted for filing and made effective by the FERC and shall remain in full force and effect until the earlier of the termination date, the termination of the Transmission Control Agreement or such other date as the Parties shall mutually agree. With respect to any such termination, the ISO must file a timely notice of termination with FERC, and this Operating Agreement shall terminate on the date FERC permits such a notice of termination to be effective.
- 2.2 Termination Date.**
- 2.2.1 Termination by Default.** Either Party (the terminating Party) may terminate this Operating Agreement by giving written notice in the event that the other Party (the defaulting Party) commits any default under this Operating Agreement and/or the ISO Tariff which, if capable of being remedied, is not remedied within 30 days after the terminating Party has given the defaulting Party written notice of the default, unless excused by reason of Uncontrollable Forces under Article X of this Operating Agreement.
- 2.2.2 Failure To Meet SUDC Definition.** Failure of a SUDC to satisfy the ISO Tariff definition of a SUDC shall be grounds for the ISO to terminate this Operating Agreement. In the event the ISO believes the SUDC no longer satisfies the ISO Tariff definition of a SUDC, the ISO shall provide written notification of the same to the SUDC and the SUDC shall have 60 days to respond. Following the 60-day response period and regardless of the position of the SUDC, if the ISO believes the SUDC no longer satisfies the ISO Tariff definition of a SUDC regardless of the response, the ISO may file a notice of termination with FERC in accordance with Section 2.2.3.
- 2.2.3 Filing.** With respect to any notice of termination given pursuant to this Section 2.2, the ISO must file a timely notice of termination with FERC. The filing of the notice of termination by the ISO will be considered timely if: (1) the request by either Party to file a notice of termination is made after the preconditions for termination have been met, and (2) the ISO files the notice of termination within 30 days of receipt of such request. This Operating Agreement shall terminate on the date FERC permits such a notice of termination to be effective.

ARTICLE III GENERAL TERMS AND CONDITIONS

- 3.1 SUDC Responsibilities.** The SUDC will be responsible to operate and maintain its SUDC Facilities in accordance with applicable reliability standards, statutes, and regulations and Good Utility Practice so as to avoid any material adverse impact on the reliability of the ISO Control Area and the ISO Controlled Grid.
- 3.2 Interconnection and SUDC Facilities.** Schedule 1 sets forth the SUDC's Generating Units, if any, and those facilities that comprise the interconnection of the SUDC Distribution System and the ISO Controlled Grid. These facilities will be considered the "SUDC Facilities" and, except as otherwise expressly provided, the provisions of this Operating Agreement shall apply only to such SUDC Facilities.

- 3.3 Non-SUDC Facilities.** To assist the ISO in cataloging non-SUDC facilities located in the ISO Control Area and for information purposes only, Schedule 2 sets forth any non-SUDC Generating Units or other facilities that are interconnected to the SUDC Distribution System. Such non-SUDC facilities are not owned or operated by the SUDC.
- 3.4 Agreement Subject to ISO Tariff.** Notwithstanding anything to the contrary herein, the Parties agree that they will comply with Section 5 of the ISO Tariff, and any other applicable provisions of the ISO Tariff specifically referenced in this Operating Agreement. This Operating Agreement shall be subject to such provisions of the ISO Tariff, which shall be deemed to be incorporated to the extent referenced herein, as the same may be changed or superseded from time to time pursuant to Sections 22.10.1 and 22.4.3 of the ISO Tariff. Nothing in this Operating Agreement shall affect in any way the authority of the ISO to unilaterally make application to FERC for a change in the ISO Tariff under Section 205 of the Federal Power Act, nor shall anything in this Operating Agreement affect the right of either Party to file a complaint under Section 206 of the Federal Power Act regarding the ISO Tariff.
- 3.5 Operation of ISO Controlled Grid.** The ISO shall operate the ISO Control Area and the ISO Controlled Grid in accordance with the ISO Tariff and the Transmission Control Agreement to which it is a party.
- 3.6 ISO Specifications and ISO Operating Procedures.**
- 3.6.1 Compliance with ISO Specifications and ISO Operating Procedures.** The SUDC will abide by and will perform all of the obligations under the ISO Specifications identified in Schedule 6 and ISO Operating Procedures identified in Schedule 9 in respect of all matters set forth therein as the same may be changed or superseded from time to time pursuant to the procedures set forth in Sections 22.10.1 and 22.4.3 of the ISO Tariff. In the event of any conflict or dispute over interpretation, those sections of the ISO Tariff identified herein shall, at all times, take precedence over such ISO Specifications and ISO Operating Procedures. The ISO shall not implement any reliability requirements, operating requirements or performance standards that would impose increased costs on the SUDC without giving due consideration to whether the benefits of such requirements or standards are sufficient to justify such increased costs. In any proceeding concerning the cost recovery by the SUDC of capital and operation and maintenance costs incurred to comply with ISO Specifications and ISO Operating Procedures, the ISO shall to the extent practicable, at the request of the SUDC, provide specific information in a form that may be readily understood by the general public regarding the nature of, and need for, the ISO-imposed requirements or standards to enable the SUDC to use this information in public hearings in support of cost recovery through rates and tariffs.
- 3.6.2 Review of ISO Specifications and ISO Operating Procedures.** The ISO shall periodically review with the SUDC the ISO Specifications identified in Schedule 6 and ISO Operating Procedures identified in Schedule 9 and shall modify such ISO Specifications and/or ISO Operating Procedure as provided in Section 3.6.1. If a new ISO Specification or ISO Operating Procedure applicable to the SUDC is adopted pursuant to Section 3.6.1, the ISO shall provide a revised version of Schedule 6 or Schedule 9 to the SUDC. Any changes to Schedule 6 or Schedule 9 will not constitute an amendment to this Operating Agreement.
- 3.6.3 Periods When Compliance is Required.** While awaiting dispute resolution or regulatory review, the SUDC shall not be required to comply with changes to the ISO Specifications and ISO Operating Procedures, except where compliance is necessary in order to prevent or remedy an imminent System Emergency.

- 3.7 Utilization of Certified Scheduling Coordinator.** The SUDC shall utilize an ISO-certified Scheduling Coordinator to schedule Energy and Ancillary Services to or from the ISO Controlled Grid. At the time when the SUDC retains such Scheduling Coordinator, the SUDC shall confirm that the Scheduling Coordinator has entered into a Scheduling Coordinator Agreement with the ISO that is currently in effect.
- 3.8 Single Point of Contact.** The ISO and the SUDC shall each provide a single point of contact for the exchange of operational procedures and information. Details of requirements relating to and the identity of the initial points of contact are set forth in Schedule 3.
- 3.9 SUDC Compliance.** In the event the ISO believes that the SUDC has failed to comply with any provision of the ISO Tariff created after the effective date applicable to the SUDC in accordance with this Operating Agreement, the ISO shall notify the SUDC of such alleged failure and, if requested, shall meet with the SUDC regarding such alleged failure to comply. If the Parties cannot reach agreement on the alleged failure to comply, then the ISO may, if applicable, invoke Section 2.2.1 of this Operating Agreement.

ARTICLE IV OPERATIONAL COORDINATION

- 4.1 Maintenance Coordination.** The SUDC shall coordinate its SUDC Facilities Outage requirements with the Participating TO with which it is interconnected. The SUDC will provide the ISO with copy of any written information regarding Outages of the SUDC Facilities that could cause a material adverse impact on the reliability of the ISO Controlled Grid. To the extent the SUDC schedules maintenance of SUDC Facilities that has a reasonable potential to cause a material adverse impact to reliability of the ISO Controlled Grid, the SUDC shall notify the ISO of such maintenance when it becomes known, and that information will be updated quarterly or as changes occur to the proposed schedule. Consistent with the SUDC's normal record generation and retention practices, the SUDC will record the details for all such work and shall provide available records when it is known, quarterly, or upon written request by the ISO.
- 4.2 System Emergencies.** The responsibilities of the Parties in relation to System Emergencies are stated in Sections 5.4, 5.5, as well as Section 34 and Section 7 of the ISO Tariff, the ISO Operating Procedures identified in Schedule 9, and in Schedule 4.
- 4.3 System Emergency Response.** The SUDC will participate in Load Shedding by reducing Load on a voluntary basis when the ISO declares a Stage 1 System Emergency. The SUDC will use any available local communication infrastructure to request that its customers curtail their electricity usage. The SUDC will not be called separately in Stage 3 System Emergencies to manually shed Load. Load restoration of any voluntary Load reduction may not commence until such time as the ISO declares that a System Emergency no longer exists. The responsibilities of the Parties to direct and to accept direction for Load reduction or other emergency plans are stated in Sections 5.4 and 5.5 of the ISO Tariff, and the ISO Operating Procedures identified in Schedule 9 and ISO Specifications identified in Schedule 6.
- 4.4 System Disturbance Load Restoration.** The responsibilities of the Parties for restoring Load following a system disturbance are stated in Section 5.5.2 of the ISO Tariff, the ISO Operating Procedures identified in Schedule 9 and ISO Specifications identified in Schedule 6, and in Schedule 5.

- 4.5 Interconnection Operation Standards.** The ISO and SUDC shall maintain stable established operating parameters and control power and reactive flow within standards stated in Schedule 6.
- 4.6 Records, Information and Reports.** The Parties are required to maintain such records, to share information, and to make such reports as are stated in Section 5.1.2, 5.6 and 5.8 of the ISO Tariff, and the ISO Operating Procedures identified in Schedule 9 and the ISO Specifications identified in Schedule 6. In accordance with Schedule 7, the SUDC will cooperate with the ISO regarding its collection, study and transmittal of system data, information, reports, and forecasts, provided that the SUDC need only provide available information to the ISO. Upon the request of the ISO, the SUDC will cooperate with the ISO regarding any ISO review following a major Outage and provide any requested information that is available.
- 4.7 Critical Protective Systems.** The SUDC shall (in accordance with Section 11.2 of this Operating Agreement) notify the ISO as soon as it is reasonably practicable of any condition that it becomes aware of that may compromise the ISO Controlled Grid Critical Protective Systems.
- 4.8 SUDC Distribution System.** The ISO shall (in accordance with Section 11.2 of this Operating Agreement) notify the SUDC as soon as is reasonably practicable of any condition which the ISO becomes aware that may compromise the operation and reliability of the SUDC Distribution System.

ARTICLE V ACCESS TO FACILITIES

- 5.1 Access Rights.** Pursuant to Section 5.9.1 of the ISO Tariff and Schedule 8 of this Operating Agreement, the ISO and the SUDC shall each have the right to install or to have installed equipment or other facilities, including metering equipment, on the electric utility property of the other necessary for the implementation of this Operating Agreement. The ISO's installation of equipment on the property of the SUDC shall comply with Local Regulatory Authority regulations, except where compliance with Local Regulatory Authority regulations would cause the ISO to violate the ISO Tariff, and with all relevant safety standards. In such case, the SUDC and ISO will work together to resolve the conflict between the Local Regulatory Authority regulations and the ISO Tariff.
- 5.2 Meter Testing.** The SUDC shall, at the request of the ISO and upon reasonable notice, provide access to its facilities necessary to permit the ISO or an ISO-approved meter inspector to perform such testing as necessary in accordance with Section 5.9.2 or 5.9.4 of the ISO Tariff and the procedures set forth in Schedule 8. For meters that are not owned by the SUDC, the ISO will obtain approval from the meter owner in advance of accessing SUDC's Facilities. Such approval shall be provided to the SUDC upon request.
- 5.3 Emergency Access Rights.** The ISO shall have a right to access the SUDC's equipment or other facilities during a System Emergency in accordance with Section 5.9.3 of the ISO Tariff. In a System Emergency, the SUDC shall have a right of access to ISO equipment on SUDC property and SUDC equipment on ISO property without notice.

ARTICLE VI COSTS

- 6.1 SUDC Operating and Maintenance Costs.** The SUDC shall be responsible for all costs incurred in connection with procuring, installing, operating and maintaining its facilities identified in Schedule 1 for the purpose of meeting its obligations under this Operating Agreement.

- 6.2 ISO Operating and Maintenance Costs.** The ISO shall be responsible for the procurement, installation, operation and maintenance costs of ISO equipment set out in Article V of this Operating Agreement installed on SUDC property.

ARTICLE VII DISPUTE RESOLUTION

- 7.1 Alternative Dispute Resolution.** The Parties shall make reasonable efforts to settle all disputes arising out of or in connection with this Operating Agreement. In the event any dispute is not settled, the Parties shall adhere to the ISO ADR Procedures set forth in Section 13 of the ISO Tariff, which is incorporated by reference, except that all reference in Section 13 of the ISO Tariff to Market Participants shall be read as a reference to the SUDC and references to the ISO Tariff shall be read as references to this Operating Agreement.

ARTICLE VIII REPRESENTATIONS AND WARRANTIES

- 8.1 Representations and Warranties.** Each Party represents and warrants that its execution, delivery and performance of this Operating Agreement has been duly authorized by all necessary corporate and/or governmental actions, to the extent authorized by law.
- 8.2 Necessary Approvals.** Each Party represents that all necessary approvals, permits, licenses, easements, right of way or access to install, own and operate its facilities subject to this Operating Agreement have been obtained prior to the effective date of this Operating Agreement.

ARTICLE IX LIABILITY

- 9.1 Extent of Liability.** The provisions of Section 14 of the ISO Tariff will apply to liability arising under this Operating Agreement, except that all references in Section 14 of the ISO Tariff to Market Participants shall be read as references to the SUDC and references to the ISO Tariff shall be read as references to this Operating Agreement.

ARTICLE X UNCONTROLLABLE FORCES

- 10.1 Uncontrollable Forces Tariff Provisions.** Section 14 of the ISO Tariff shall be incorporated by reference into this Operating Agreement, except that all references in Section 14 of the ISO Tariff to Market Participants shall be read as a reference to the SUDC and references to the ISO Tariff shall be read as references to this Operating Agreement.

ARTICLE XI MISCELLANEOUS

- 11.1 Assignments.** Either Party may assign its obligations under this Operating Agreement, with the other Party's prior written consent, in accordance with Section 22.2 of the ISO Tariff, which is incorporated by reference into this Operating Agreement. Such consent shall not be unreasonably withheld.

- 11.2 Notices.** Any notice, demand or request which may be given to or made upon either Party regarding this Operating Agreement shall be made in accordance with Section 22.4 of the ISO Tariff, which is incorporated by reference, except that all reference in Section 22.4 to Market Participants shall be read as a reference to the SUDC. A Party must update the information in Schedule 3 of this Operating Agreement as that information changes in accordance with Section 22.4 of the ISO Tariff. Such changes will not constitute an amendment to this Operating Agreement.
- 11.3 Waivers.** Any waiver at any time by either Party of its rights with respect to any default under this Operating Agreement, or with respect to any other matter arising in connection with this Operating Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or matter arising in connection with this Operating Agreement. Any delay short of the statutory period of limitations, in asserting or enforcing any right under this Operating Agreement, shall not constitute or be deemed a waiver of such right.
- 11.4 Governing Law and Forum.** This Operating Agreement shall be deemed to be a contract made under and for all purposes shall be governed by and construed in accordance with the laws of the State of California except in its conflict of laws provisions. The Parties irrevocably consent that any legal action or proceeding arising under or in relation to this Operating Agreement to which the ISO ADR Procedures do not apply, shall be brought in any of the following forums, as appropriate: any court of the State of California, any federal court of the United States of America located in the State of California or, where subject to its jurisdiction, before the Federal Energy Regulatory Commission.
- 11.5 Consistency with Federal Laws and Regulations.**
- (a) Nothing in this Operating Agreement shall compel any person or federal entity to: (1) violate federal statutes or regulations; or (2) in the case of a federal agency, to exceed its statutory authority, as defined by any applicable federal statutes, regulations, or orders lawfully promulgated thereunder. If any provision of this Operating Agreement is inconsistent with any obligation imposed on any person or federal entity by federal law or regulation to that extent, it shall be inapplicable to that person or federal entity. No person or federal entity shall incur any liability by failing to comply with this Operating Agreement that is inapplicable to it by reason of being inconsistent with any federal statutes, regulations, or orders lawfully promulgated thereunder; provided, however, that such person or federal entity shall use its best efforts to comply with the ISO Tariff to the extent that applicable federal laws, regulations, and orders lawfully promulgated thereunder permit it to do so.
 - (b) If any provision of this Operating Agreement requiring any person or federal entity to give an indemnity or impose a sanction on any person is unenforceable against a federal entity, the ISO shall submit to the Secretary of Energy or other appropriate Departmental Secretary a report of any circumstances that would, but for this provision, have rendered a federal entity liable to indemnify any person or incur a sanction and may request the Secretary of Energy or other appropriate Departmental Secretary to take such steps as are necessary to give effect to any provisions of this Operating Agreement that are not enforceable against the federal entity.
- 11.6 Integration.** This Operating Agreement constitutes the full agreement of the Parties with respect to the subject matter hereto and supercedes all prior agreements, whether written or oral, with respect to such subject matter.

- 11.7 Severability.** If any term, covenant, or condition of this Operating Agreement or the application or effect of any such term, covenant, or condition is held invalid as to any person, entity, or circumstance, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in force and effect to the maximum extent permitted by law, and all other terms, covenants, and conditions of this Operating Agreement and their application shall not be affected thereby, but shall remain in force and effect and the Parties shall be relieved of their obligations only to the extent necessary to eliminate such regulatory or other determination unless a court or governmental agency of competent jurisdiction holds that such provisions are not separable from all other provisions of this Operating Agreement.
- 11.8 Penalties.** Any penalties to be levied under this Operating Agreement shall be established in accordance with the ISO Tariff and approved by the FERC. Nothing in this Operating Agreement, with the exception of the provisions relating to ADR, shall be construed as waiving the rights of the SUDC 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 SUDC.
- 11.9 Section Headings:** Section headings provided in this Operating Agreement are for ease of reading and are not meant to interpret the text in each Section.
- 11.10 Amendments.** This Operating Agreement and the Schedules attached hereto may be amended from time to time by the mutual agreement of the Parties in writing. Amendments that require FERC approval shall not take effect until FERC has accepted such amendments for filing and made them effective. If the amendment does not require FERC approval, the amendment will be filed with FERC for information.
- 11.11 Counterparts.** This Operating Agreement may be executed in one or more counterparts at different times, each of which shall be regarded as an original and all of which, taken together, shall constitute one and the same Operating Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Operating Agreement to be duly executed on behalf of each by and through their authorized representatives as of the date hereinabove written.

California Independent System Operator Corporation

By: _____
Name: _____
Title: _____
Date: _____

[Full name of SUDC]

By: _____
Name: _____
Title: _____
Date: _____

SCHEDULE 1

SYSTEM INTERCONNECTION FACILITIES

[List to be provided in accordance with the SUDC Operating Agreement.]

SCHEDULE 2

Non-SUDC FACILITIES

[List to be provided in accordance with the SUDC Operating Agreement.]

SCHEDULE 3
OPERATIONAL CONTACTS

ISO:

Transmission Dispatcher
(Folsom): _____
Transmission Dispatcher
(Alhambra): _____
Generator Dispatcher:
(Folsom-Primary) _____
Generator Dispatcher:
(Alhambra-Backup) _____
Real Time Scheduler:
(Folsom) _____
Real Time Scheduler:
(Alhambra) _____

Pre Scheduler: _____

Shift Manager: _____
Control Room fax: _____

Outage Coordination: _____
Fax: _____

Director of Grid Operations: _____

WECC Reliability Coordinator: _____

SUDC:

Name of Operations
Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email address: _____

Phone: _____

Fax: _____

Name of Alternative
Representative: _____

Title: _____

Email address: _____

Phone: _____

Fax: _____

CONTACTS FOR NOTICES

SUDC

Name of Primary
Representative: _____
Title: _____
Address: _____
City/State/Zip Code: _____
Email Address: _____
Phone: _____
Fax No: _____

Name of Alternative
Representative: _____
Title: _____
Address: _____
City/State/Zip Code: _____
Email Address: _____
Phone: _____
Fax No: _____

ISO

Name of Primary

Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email Address: _____

Phone: _____

Fax No: _____

Name of Alternative

Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email Address: _____

Phone: _____

Fax No: _____

SCHEDULE 4
SYSTEM EMERGENCIES

The ISO will notify the SUDC's operational contact, as identified in Schedule 2, of the emergency, including information regarding the cause, nature, extent, and potential duration of the emergency. The SUDC contact will then take such actions as are appropriate for the emergency.

The SUDC will make requests for information from the ISO regarding emergencies through the ISO Operations Shift Manager, by the SUDC's operational contact, or the SUDC may coordinate public information with the ISO Communication Coordinator.

For transmission system caused outages the ISO Operations Shift Manager will notify the SUDC contact of any information related to the outage such as cause, nature, extent, potential duration and customers affected.

Available SUDC information and ISO Grid Control Center logs, ISO Electric Switching Orders and ISO Energy Management System temporal database will be used in the ISO's preparation of outage reviews. These documents are defined as the chronological record of the operation of the activities which occur with the portion of the electrical system assigned to that control center. The log shall contain all pertinent information, including orders received and transmitted, relay operations, messages, clearances, accidents, trouble reports, daily switching program, etc.

The SUDC will retain records in accordance with its record retention policy or practice, provided the records associated with this Operating Agreement are retained for a minimum of six years.

SCHEDULE 5

SYSTEM DISTURBANCE LOAD RESTORATION

If the SUDC is required to shed load, the SUDC will follow the procedures set forth below in this Schedule 5 in promoting orderly, coordinated restoration of electric systems after a major system disturbance has occurred which resulted in load shedding by frequency relays in California.

1. Immediately after load shedding has occurred in the SUDC, the SUDC will remain in contact with their respective Participating Transmission Owner (PTO) Area Control Center (ACC) until normal frequency has been restored throughout the ISO Control Area or the ISO Shift Manager has concluded that such full-time communications can be terminated. Emergency communications over the California ACC Hot-line will be under the direction of the ISO Shift Manager and the senior dispatcher present at the affected PTO ACC(s).
2. Manual load restoration will not normally be initiated until the California ACC Hot Line is attended. No load is to be manually restored unless directed by the ISO, either directly or through its assignee, provided that the procedure for the ISO's designation of any assignee is agreed to by the SUDC, after the frequency has recovered and there is indication that the frequency can be maintained. The SUDC will await direction from the ISO or its assignee, who will be in contact with the ISO Shift Manager. The ISO Shift Manager will determine whether adequate generation resources are available on line to support the load to be restored.
3. If the ISO cannot meet the WECC and NERC Control Area Disturbance Control Standard or the Control Performance Standard post disturbance, no manual load restoration will be permitted. If the frequency is such that automatic load restoration occurs under these conditions, if the SUDC has restored load automatically, it will manually shed an equivalent amount of load to offset the load which was automatically restored.

SCHEDULE 6

INTERCONNECTION OPERATION STANDARDS

The ISO and SUDC shall jointly maintain stable operating parameters and control power and reactive flow in accordance with the capabilities of the SUDC, the ISO Tariff and the following interconnection operation standards.

SUDC Responsibilities

1. The SUDC shall operate its SUDC Facilities at each point of interconnection with the ISO Controlled Grid in such manner as to avoid any material adverse impact on the reliability of the ISO Controlled Grid. In accordance with this performance goal, the SUDC shall: i) operate its SUDC Facilities at each point of interconnection with the ISO Controlled Grid in accordance with Good Utility Practice with respect to normal ratings, emergency ratings, voltage limits, and balance of load between electrical phases; and ii) maintain load power factor at each point of interconnection with the ISO Controlled Grid as close as reasonably possible to unity power factor and consistent with Good Utility Practice.

ISO Responsibilities

1. The ISO shall operate the ISO Controlled Grid at each point of interconnection with the SUDC in accordance with the ISO Tariff and in such manner as to avoid any material adverse impact on the SUDC Facilities. In accordance with this performance goal, the ISO shall:
2. At the request of the SUDC, participate with the SUDC and Participating TO in the development of joint power quality performance standards and jointly maintain compliance with such standards.
3. Observe SUDC grid voltage limits specified in Attachment 1 including requirements for reduced voltage on ISO Controlled Grid facilities which apply during heavy fog (or other unusual operating conditions) as needed to minimize the risk of insulator flashover.
4. At the request of the SUDC, support SUDC investigation of power quality incidents, and provide related data to the SUDC in a timely manner.
5. Support installation of apparatus on the ISO Controlled Grid to improve power quality, and take all reasonable measures to investigate and mitigate power quality concerns caused by actions or events in neighboring systems or Control Areas.
6. Maintain, or cause to be maintained, load power factor at each SUDC Interconnection as close as reasonably possible to unity power factor and consistent with Good Utility Practice, pursuant to Section 2.5.3.4 of the ISO Tariff.

The Parties may adopt additional operations standards for the interconnection provided such standards are in writing and are mutually agreed to.

SCHEDULE 6
ATTACHMENT 1

SUDC GRID VOLTAGE LIMITS

[To be determined.]

SCHEDULE 7

RECORDS, INFORMATION, REPORTS

The SUDC shall provide available information to the ISO relating to SUDC system operations reasonably related to system reliability of the ISO Controlled Grid. The Parties shall jointly develop any necessary forms and procedures for collection, study and transmittal of system data, information, reports and forecasts.

SCHEDULE 8

RIGHTS OF ACCESS TO FACILITIES

- 1. Equipment Installation.** In order to give effect to this Operating Agreement, a Party that requires the use of particular equipment (the equipment owner) may require installation of such equipment on property owned by the other Party (the property owner), provided that the equipment is necessary to meet the equipment owner's service obligations and that the equipment shall not have a negative impact on the reliability of the service provided, nor prevent the property owner from performing its own obligations or exercising its rights under this Operating Agreement.
- 2. Free Access.** The property owner shall grant to the equipment owner free of charge reasonable installation rights and rights of access to accommodate equipment inspection, maintenance, repair, upgrading, or removal for the purposes of this Operating Agreement, subject to the property owner's reasonable safety, operational, and future expansion needs.
- 3. Notice.** The equipment owner shall provide reasonable notice to the property owner when requesting access for site assessment, equipment installation, or other relevant purposes. Such access shall not be provided unless the parties mutually agree to the date, time, and purpose of each access. Agreement on the terms of the access shall not be unreasonably withheld or delayed.
- 4. Removal of Installed Equipment.** Following reasonable notice, the equipment owner shall be required, at its own expense, to remove or relocate equipment, at the request of the property owner, provided that the equipment owner shall not be required to do so if it would have a negative impact on the reliability of the service provided, or be prevented from performing its own obligations or exercising its rights under this Operating Agreement.
- 5. Costs.** The equipment owner shall repair at its own expense any property damage it causes in exercising its rights and shall reimburse the property owner for any other reasonable costs that it may be required to incur to accommodate the equipment owner's exercise of its rights under Section 1 or Section 4.
- 6. Rights to Assets.** The Parties shall not interfere with each other's assets, without prior written agreement.
- 7. Inspection of Facilities.** In order to meet their respective obligations under this Operating Agreement, the ISO may view or inspect SUDC Facilities and the SUDC may view or inspect ISO Grid facilities. Provided that reasonable notice is given, a Party shall not unreasonably deny access to such facilities for viewing or inspection by the requesting Party.
- 8. Access During Emergencies.** Either Party shall have rights of access, without prior notice, to the other Party's equipment as necessary during times of a System Emergency.

SCHEDULE 9

SUDC OPERATING PROCEDURES

[To be determined.]

ISO TARIFF APPENDIX C
ISO Scheduling Process

Day-Ahead Schedule Timeline

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

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

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

ISO TARIFF APPENDIX D
Black Start Units

Appendix D - Black Start Units

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

- (a) Black Start Units must be capable of starting and paralleling with the ISO Controlled Grid without aid from the ISO Controlled Grid;
- (b) Black Start Units must be capable of making a minimum number of starts per event (to be without aid from the ISO Controlled Grid as determined by the ISO);
- (c) Black Start Units must be equipped with governors capable of operating in the stand alone (asynchronous) and parallel (synchronous) modes.
- (d) Black Start Units must have startup load pickup capabilities at a level to be determined by the ISO, including total startup load (MW) and largest startup load (MW) for such power output levels as the ISO may specify.
- (e) All Black Start Units must be capable of producing Reactive Power (boost) and absorbing Reactive Power (buck) as required by the ISO to control system voltages. This requirement may be met by the operation of more than one Black Start Unit in parallel providing that:
 - (i) the Black Start generation supplier demonstrates that the proposed Generation resource shares reactive burden equitably;
 - (ii) all Participating Generators associated with the proposed Black Start source are located in the same general area.

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

- (f) All Black Start Units must have the following communication/control requirements:
 - (i) dial-up telephone;
 - (ii) backup radio;
 - (iii) manning levels which accord with Good Utility Practice.

ISO TARIFF APPENDIX E
Verification of Submitted Data for Ancillary Services

Appendix E

Verification of Submitted Data for Ancillary Services

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

1. Bid File and Schedule Format. The ISO shall verify that the bid files and schedules conform to the format specified for the type of Ancillary Service bid or schedule submitted. If the bid file or schedule does not conform to specifications, it shall be annotated by the ISO to indicate the location of the errors, and returned to the Scheduling Coordinator for corrections. Any changes made by a Scheduling Coordinator shall require a new submittal of bid or schedule information, and all validity checks shall be performed on the re-submitted bid or schedule.
2. Generation Schedules and Bids.
 - 2.1. Quantity Data. The ISO shall verify that no Scheduling Coordinator is submitting a scheduled or bid quantity for Regulation, Spinning Reserve, Non-Spinning or Replacement Reserve which exceeds available capacity for Regulation and Reserves on the Generating Units, Loads and resources scheduled for that Settlement Period.
 - 2.2. Location Data. The ISO shall verify that the location data corresponds to the ISO Controlled Grid interconnection data.
 - 2.3. Operating Capability. The ISO shall verify that the operating capability data corresponds to the ISO Controlled Grid interconnection data for each Generating Unit, Load or other resource for which a Scheduling Coordinator is submitting an Ancillary Service bid or schedule.
3. Load Schedules and Bids.
 - 3.1. Quantity data. The ISO shall verify that the quantity of Non-Spinning and Replacement Reserve scheduled or bid from Dispatchable Load does not exceed scheduled consumption quantities for that Settlement Period.
 - 3.2. Location data. The ISO shall verify that the location of the Dispatchable Load corresponds to the ISO Controlled Grid interconnection data for each supplier of Dispatchable Load.
4. Notification of Validity or Invalidity of Ancillary Services Schedules and Competitive Bids. The ISO shall, as soon as reasonably practical following the receipt of competitive bids or self-provided Ancillary Service schedules, send to the Scheduling Coordinator who submitted the schedule or bid the following information:
 - (a) acknowledgment of receipt of the competitive bid or self-provided Ancillary Service schedule;
 - (b) notification that the bid or schedule has been accepted or reject for non-compliance with the rules specified in this Appendix. If a bid or schedule is rejected, such notification shall contain an explanation of why the bid or schedule was not accepted;

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

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

5. Treatment of Missing Values.

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

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

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

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

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

ISO TARIFF APPENDIX F
Rate Schedules

ISO TARIFF APPENDIX F
Schedule 1

Grid Management Charge

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

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

1. The rate in \$/MW for the Core Reliability Services – Demand Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total of the forecasted Scheduling Coordinators' metered non-coincident peak hourly demand in MW for all months during the year (excluding the portion of such Demand associated with Energy Exports, if any, as may be modified in accordance with Part F of this Schedule 1), reduced by thirty-four (34) percent of the sum of all Scheduling Coordinators' metered non-coincident peaks occurring during the hours ending 0100 through 0600, or during the hours ending 2300 through 2400, every day, including Sundays and holidays; provided that if a Scheduling Coordinator's metered non-coincident peak hour during the month occurs during the hours ending 0100 through 0600, or during the hours ending 2300 through 2400, every day, the rate shall be sixty-six (66) percent of the standard Core Reliability Services – Demand rate.
2. The rate in \$/MWh for the Core Reliability Services – Energy Export Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total of the forecasted Scheduling Coordinators' metered volume of Energy Exports in MWh, as may be modified in accordance with Part F of this Schedule 1, for all months during the year.
3. The rate in \$/MWh for the Energy Transmission Services Net Energy Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total annual forecasted Metered Control Area Load.
4. The rate in \$/MWh for the Energy Transmission Services Uninstructed Deviations Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the absolute value of total annual forecasted net uninstructed deviations (netted within a Settlement Interval summed over the calendar month) in MWh.
5. The rate in \$ per Schedule for the Forward Scheduling Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecasted number of non-zero MW Final Hour-Ahead Schedules, as may be modified in accordance with Part F of this Schedule 1, including all awarded Ancillary Service bids; provided that the Forward Scheduling charge attributable to Final Hour-Ahead Schedules for Inter-Scheduling Coordinator Energy and Ancillary Service Trades

- for each Scheduling Coordinator is fifty (50) percent of the standard Forward Scheduling Charge.
6. The rate in \$/MWh for the Congestion Management Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the total annual forecasted Scheduling Coordinators' inter-zonal scheduled flow (excluding flows pursuant to Existing Contracts) per path in MWh.
 7. The rate in \$/MWh for the Market Usage Charge will be calculated by dividing the GMC costs, as determined in accordance with Part C of this Schedule 1, allocated to this service category in accordance with Part E of this Schedule 1, by the annual forecasted total purchases and sales (including out-of-market transactions) of Ancillary Services, Supplemental Energy, Instructed Imbalance Energy, and net Uninstructed Imbalance Energy (with uninstructed deviations being netted within a Settlement Interval summed over the calendar month) in MWh.
 8. The rate for the Settlements, Metering, and Client Relations Charge will be fixed at \$500.00 per month, per Scheduling Coordinator Identification Number ("SC ID") with an invoice value other than \$0.00 in the current trade month.

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

Part B – Quarterly Adjustment, If Required

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

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

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

Part C – Costs Recovered through the GMC

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

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

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

adjusted annually for:

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

divided by:

- forecasted annual billing determinant volumes;

adjusted quarterly for:

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

The Grid Management Charge revenue requirement formula is as follows:

Grid Management Charge revenue requirement =

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

Where,

- Operating Expenses = O&M Expenses plus Taxes Other Than Income Taxes and Penalties
O&M Expenses = Transmission O&M Expenses (Accounts 560-574) plus Customer Accounting Expenses (Accounts 901-905) plus Customer Service and Informational Expenses (Accounts 906-910) plus Sales Expenses (Accounts 911-917) plus Administrative & General Expenses (Accounts 920-935)
- Taxes Other Than Income Taxes = those taxes other than income taxes which relate to ISO operating income (Account 408.1)
- Penalties = payments by the ISO for penalties or fines incurred for violation of WECC reliability criteria (Account 426.3)
- Debt Service = for any fiscal year, scheduled principal and interest payments, sinking fund payments related to balloon maturities, repayment of commercial paper notes, net payments required pursuant to a payment obligation, or payments due on any ISO notes. This amount includes the current year accrued principal and interest payments due in April of the following year.
- Coverage Requirement = 25% of the Senior Lien Debt Service.
- Senior Lien Debt Service = all Debt Service that has a first lien on ISO Net Operating Revenues (Account 128 subaccounts).
- Cash Funded Capital Expenditures = Post current fiscal year capital additions (Accounts 301-399) funded on a pay-as-you-go basis.
- Interest Earnings = Interest earnings on Operating and Capital Reserve balances (Account 419). Interest on bond or note proceeds specifically designated for capital projects or capitalized interest is excluded.

- Other Revenues = Amounts booked to Account 456 subaccounts. Such amounts include but are not limited to application fees, WECC reliability coordinator reimbursements, Line Operator Charges, and fines assessed and collected by the ISO.
- Reserve Transfer = the projected reserve balance for December 31 of the prior year less the Reserve Requirement as adopted by the ISO Governing Board and FERC. If such amount is negative, the amount may be divided by two, so that the reserve is replenished within a two-year period. (Account 128 subaccounts)
- Reserve Requirement = 15% of Annual Operating Expenses.

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

Part D – Information Requirements

Budget Schedule

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

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

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

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

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

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

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

Budget Posting

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

Annual Filing

If the Grid Management Charge revenue requirement for Budget Year 2008 does not exceed \$195 million, the ISO shall not be required to make a Section 205 filing to adjust the GMC charges calculated in accordance with this Schedule 1 to recover such Revenue Requirement. In order for the ISO to adjust the GMC charges to collect a Grid Management Charge Revenue Requirement for Budget Year 2008 that exceeds \$195 million, the ISO must submit an application to FERC under Section 205. In any event, the ISO shall submit a filing under Section 205 for approval of the GMC charges to be effective the earlier of January 1, 2009 or the effective date of amendments to the ISO Tariff implementing a new market design based on a nodal system of Congestion Management employing locational marginal pricing, such as the ISO's Market Redesign and Technology Upgrade ("MRTU"). In such filing, the ISO may revise the GMC rates set forth in this Schedule 1, but shall not be required to do so.

Periodic Financial Reports

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

Part E – Cost Allocation

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

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

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

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

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

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

Table 1
O&M, Debt Service, and Other Expense Recoveries Cost Allocation Factors

CC #	Cost Center	CRS	ETS	FS	CM	MU	SMCR	Total
1100	CEO Division	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1111	CEO - General	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1241	MD02	6.95%	0%	13.86%	10.91%	28.38%	39.90%	100%
1521	Grid Planning	62.50%	37.50%	0%	0%	0%	0%	100%
1300	Finance Division	44.04%	21.49%	3.62%	4.22%	10.31%	16.32%	100%
1311	CFO - General	44.04%	21.49%	3.62%	4.22%	10.31%	16.32%	100%
1321	Accounting	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1331	Financial Planning and Treasury	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1351	Facilities	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
1361	Security & Corporate Services	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%

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1400	Information Services Division	38.25%	7.16%	9.74%	4.78%	9.23%	30.85%	100%
1411	Chief Information Officer	38.25%	7.16%	9.74%	4.78%	9.23%	30.85%	100%
1422	Corporate & Enterprise Applications	33.28%	7.06%	1.16%	25.28%	12.58%	20.63%	100%
1424	Asset Management	35.30%	6.12%	10.91%	4.88%	10.50%	32.29%	100%
1431	End User Support	37.80%	14.44%	8.29%	3.5%	9.32%	26.65%	100%
1432	Computer Operations and Infrastructure Services	34.15%	9.21%	11.76%	3.08%	8.69%	33.11%	100%
1433	Network Services	43.38%	11.88%	9.39%	2.61%	9.23%	23.51%	100%
1441	Outsourced Contracts	42.25%	10.62%	10.25%	2.53%	9.07%	25.28%	100%
1442	Production Support	25.09%	0.17%	17.98%	2.62%	7.52%	46.62%	100%
1451	Information Support Services	25.09%	0.17%	17.98%	2.62%	7.52%	46.62%	100%
1461	Control Systems	96.44%	2.44%	0%	0%	0.56%	0.56%	100%
1462	Field Data Acquisition System (FDAS)	21.43%	0%	0%	0%	0%	78.57%	100%
1463	Operations Systems Services	50.44%	2.91%	6.01%	1.21%	5.95%	33.49%	100%
1466	Enterprise Applications	47.98%	7.30%	1.19%	1.34%	3.47%	38.72%	100%
1467	Settlement Systems Services	27.34%	11.20%	1.83%	2.05%	5.32%	52.25%	100%
1468	Corporate Application Support and Administration	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
1469	Analytical and Reporting Applications	10%	0%	0%	65%	25%	0%	100%
1471	IT Planning	25.09%	0.17%	17.98%	2.62%	7.52%	46.62%	100%

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1481	Markets and Scheduling System Services	46.85%	2.86%	23.68%	2.5%	17.64%	6.48%	100%
1482	Market Systems Support Services	44.94%	1.05%	18.51%	6.17%	23.78%	5.54%	100%
1500	Grid Operations Division	66.71%	33.29%	0%	0%	0%	0%	100%
1511	VP Grid Operations	66.71%	33.29%	0%	0%	0%	0%	100%
1542	Outage Coordination	95.11%	4.89%	0%	0%	0%	0%	100%
1543	Loads and Resources	48.95%	51.05%	0%	0%	0%	0%	100%
1544	Real-Time Scheduling	60%	40%	0%	0%	0%	0%	100%
1545	Grid Operations	67.47%	32.53%	0%	0%	0%	0%	100%
1546	Security Coordination	100%	0%	0%	0%	0%	0%	100%
1547	Engineering and Maintenance	46.42%	53.58%	0%	0%	0%	0%	100%
1548	OSAT Group - General	93.2%	6.80%	0%	0%	0%	0%	100%
1549	Operations Training	50.48%	49.52%	0%	0%	0%	0%	100%
1554	Special Projects Engineering	42.86%	57.14%	0%	0%	0%	0%	100%
1555	Operations Support Group	55.56%	44.44%	0%	0%	0%	0%	100%
1558	Transmission Maintenance	58.46%	41.54%	0%	0%	0%	0%	100%
1559	Operations Application Support	60%	40%	0%	0%	0%	0%	100%
1561	Operations Engineering South	65.32%	34.68%	0%	0%	0%	0%	100%
1562	Operations Engineering North	55.15%	44.85%	0%	0%	0%	0%	100%
1563	Operations Coordination	74.55%	25.45%	0%	0%	0%	0%	100%
1564	Operations Scheduling	100%	0%	0%	0%	0%	0%	100%
1565	Pre-Scheduling and Support	76.92%	23.08%	0%	0%	0%	0%	100%

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1566	Regional Coordination - General	100%	0%	0%	0%	0%	0%	100%
1600	Legal and Regulatory Division	35.80%	21.78%	3.73%	7.18%	16.97%	14.54%	100%
1611	VP General Counsel - General	35.80	21.78%	3.73%	7.18%	16.97%	14.54%	100%
1631	Legal and Regulatory	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1641	Market Analysis	15.32%	26.33%	0%	19.90 %	31.38%	7.07%	100%
1642	Market Surveillance Committee	25%	25%	0%	25%	25%	0%	100%
1651	ISO Governing Board	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1661	Compliance - General	21.90%	20.37%	11.90 %	0%	28.50%	17.33%	100%
1662	Compliance - Audits	8.33%	0%	0%	0%	50%	41.67%	100%
1700	Market Services Division	17.14%	2.43%	9.46%	9.39%	20.35%	41.23%	100%
1711	VP Market Services - General	17.14%	2.43%	9.46%	9.39%	20.35%	41.23%	100%
1721	Billing and Settlements- General	25%	0%	0%	0%	0%	75%	100%
1722	Business Development Support	0%	0%	0%	0%	0%	100%	100%
1723	RMR Settlements	80.30%	19.70%	0%	0%	0%	0%	100%
1724	BBS - PSS	0%	0%	0%	0%	0%	100%	100%
1725	BBS - FSS	0%	0%	0%	0%	0%	100%	100%
1731	Contracts and Special Projects	43.17%	6.83%	0%	0%	0%	50%	100%
1741	Client Relations	0%	0%	0%	0%	0%	100%	100%
1751	Market Operations - General	30.66%	0%	15.33 %	15.33 %	34.85%	3.83%	100%

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1752	Manager of Markets	27.31%	5.46%	27.31 %	21.84 %	18.08%	0%	100%
1753	Market Engineering	21.32%	0%	0%	28.43 %	43.15%	7.11%	100%
1755	Business Solutions	5.91%	0%	47.27 %	11.82 %	29.10%	5.91%	100%
1756	Market Quality - General	0%	0%	0%	0%	70.93%	29.07%	100%
1757	Market Integration	7.38%	0%	29.52%	29.52%	26.20%	7.38%	100%
1800	Corporate and Strategic Development Division	44.04%	21.49%	3.62%	4.21%	10.31%	16.33%	100%
1811	VP Corporate and Strategic Development - General	44.04%	21.49%	3.62%	4.21%	10.31%	16.33%	100%
1821	Communications	44.01%	22.51%	3.78%	4.61%	10.45%	15.63%	100%
1831	Strategic Development	44.01%	22.51%	3.78%	4.61%	10.45%	15.63%	100%
1841	Human Resources	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
1851	Project Office	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
1861	Regulatory Policy	44.01%	21.51%	3.78%	4.61%	10.45%	15.63%	100%
Other Revenue and Credits								
	SC Application and Training Fees	0%	0%	0%	0%	0%	100%	100%
	WECC Reimbursement/NERC Reimbursement	100%	0%	0%	0%	0%	0%	100%
	Interest Earnings	36.64%	12.29%	9.34%	4.97%	11.47%	25.30%	100%
Debt Service Related Allocations		33.49%	7.93%	15.26%	5.19%	9.44%	28.69%	100%

Table 2

Capital Cost Allocation Factors

System	CRS	ETS	FS	CM	MU	SMCR	Total
ACC Upgrades (Communication between ISO & IOUs)	100%	0%	0%	0%	0%	0%	100%
Ancillary Services Management (ASM) Component of SA	15%	0%	40%	0%	45%	0%	100%
Application Development Tools	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Automated Dispatch System (ADS)	50%	0%	25%	0%	20%	5%	100%
Automated Load Forecast System (ALFS)	70%	0%	10%	0%	20%	0%	100%
Automatic Mitigation Procedure (AMP)	85%	0%	0%	0%	15%	0%	100%
Backup systems (Legato/Quantum)	23%	0%	22%	3%	7%	45%	100%
Balance of Business Systems (BBS)	0%	0%	0%	0%	0%	100%	100%
Balancing Energy Ex Post Price (BEEP) Component of SA	50%	0%	20%	10%	20%	0%	100%
Bill's Interchange Schedule (BITS)	85%	0%	0%	0%	15%	0%	100%
CaseWise (process modeling tool)	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
CHASE	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Common Information Model (CIM)	100%	0%	0%	0%	0%	0%	100%
Compliance (Blaze)	19.17%	16.27%	9.5%	0%	32.83%	22.23%	100%
Congestion Management (CONG) (Component of SA)	10%	0%	0%	65%	25%	0%	100%

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Congestion Reform-DSOW	50%	0%	0%	50%	0%	0%	100%
Congestion Revenue Rights (CRR)	0%	0%	0%	80%	20%	0%	100%
DataWarehouse	24.46%	18.27%	6.40%	8.74%	24.30%	17.82%	100%
Dept. of Market Analysis Tools (SAS/MARS)	15.32%	26.33%	0%	19.90%	31.38%	7.07%	100%
Dispute Tracking System (Remedy)	0%	0%	0%	0%	0%	100%	100%
Documentum	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Electronic Tagging (Etag)	100%	0%	0%	0%	0%	0%	100%
Energy Management System (EMS)	100%	0%	0%	0%	0%	0%	100%
Engineering Analysis Tools	60%	40%	0%	0%	0%	0%	100%
Evaluation of Market Separation	0%	0%	0%	50%	50%	0%	100%
Existing Transmission Contracts Calculator (ETCC)	25%	0%	20%	15%	20%	20%	100%
FERC Study Software	0%	0%	0%	0%	100%	0%	100%
Firm Transmission Right (FTR) and Secondary Registration System (SRS)	0%	0%	15%	60%	15%	10%	100%
Global Resource Reliability Management Application (GRRMA)	75%	15%	0%	0%	10%	0%	100%
Grid Operations Training Simulator (GOTS)	56%	44%	0%	0%	0%	0%	100%
Hour-Ahead Data AnalysisTool, Day-Ahead Data AnalysisTool,	0%	0%	100%	0%	0%	0%	100%
Human Resources	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%

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IBM Contract	37.26%	14.44%	9.54%	3.52%	9.10%	26.13%	100%
Integrated Forward Market (IFM)	10%	0%	35%	0%	55%	0%	100%
Internal Development	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Interzonal Congestion Management reform - Real Time	50%	0%	0%	50%	0%	0%	100%
Land and Building Costs	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Local Area Network (LAN)	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Locational Marginal Pricing (LMPM)	10%	0%	35%	0%	55%	0%	100%
Market Transaction System (MTS)	0%	0%	0%	0%	100%	0%	100%
Masterfile	20%	0%	20%	0%	55%	5%	100%
MD02 Capital	6.95%	0%	13.86%	10.91%	28.38%	39.90%	100%
Meter Data Acquisition System (MDAS)	0%	0%	0%	0%	0%	100%	100%
Miscellaneous (2004 related projects)	23.46%	0%	21.78%	2.68%	6.86%	45.04%	100%
Monitoring (Tivoli)	23.46%	0%	21.78%	2.68%	6.86%	45.04%	100%
New Resource Interconnection (NRI)	100%	0%	0%	0%	0%	0%	100%
New System Equipment (replacement of owned equipment)	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
NT/web servers	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
NT-servers	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Oracle Enterprise Manager (OEM)	27%	0.0%	18%	5%	9%	41%	100%

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

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Remedy (related to Transmission Registry, New Resource Interconnection, and Resource Registry)	100%	0%	0%	0%	0%	0%	100%
Remote Intelligent Gateway (RIG) & Data Processing Gateway (DPG)	100%	0%	0%	0%	0%	0%	100%
Resource Register (RR)	100%	0%	0%	0%	0%	0%	100%
RMR Application Validation Engine (RAVE)	100%	0%	0%	0%	0%	0%	100%
Scheduling & Logging for ISO California (SLIC)	65%	0%	15%	5%	15%	0%	100%
Scheduling Architecture (SA)	23.96%	0%	19.84%	25.87%	30.33%	0%	100%
Scheduling Infrastructure (SI)	0%	0%	93.92%	0%	6.08%	0%	100%
Scheduling Infrastructure Business Rules (SIBR)	0%	0%	93.92%	0%	6.08%	0%	100%
Security Constrained Economic Dispatch (SCED)	40%	0%	0%	0%	60%	0%	100%
Security- External/Physical	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Security-ISS (CUDA)	23%	0%	22%	3%	7%	45%	100%
Settlements and Market Clearing	0%	0%	0%	0%	0%	100%	100%
Sign Board (Symon Board maint.)	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Startup Costs through 3/31/98, Working Capital-3 months	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Storage (EMC symmetrix)	18.67%	9.55%	13.71%	4.21%	11.77%	42.09%	100%
System Equipment Buyouts (lease buyouts)	43.27%	1.02%	7.34%	1.79%	11.03%	35.56%	100%

Telephone/PBX	44.06%	21.47%	3.51%	3.93%	10.21%	16.81%	100%
Training Systems	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Transmission Constrained Unit Commitment (TCUC) Must Offer Obligation	100%	0%	0%	0%	0%	0%	100%
Transmission Map Plotting & Display	50%	50%	0%	0%	0%	0%	100%
Trustee Costs, Interest-Capitalized, User Groups	53.60%	0.55%	10.62%	15.74%	17.48%	2%	100%
Utilities - System i.e. Print drivers	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Vitria (Middleware)	23.46%	0.18%	21.78%	2.68%	6.86%	45.04%	100%
Wide Area Network (WAN)	40.80%	2.14%	18.68%	1.31%	7.60%	29.48%	100%
Capital Expenditures for Systems not Specified	32.20%	7.40%	15%	5.50%	10.60%	29.30%	100%

Table 3

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

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

Part F – Other Modifications to the Rates

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

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

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

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

ISO TARIFF APPENDIX F
Schedule 2
Other Charges

Voltage Support Service

The user rate per unit of purchased Voltage Support will be calculated in accordance with the formula in ISO Tariff Section 8.12.4

Regulation Service

Regulation Obligation:

The amount of Regulation required will be calculated in accordance with Section 8.2.3 of the ISO Tariff.

Regulation Rates:

The formulas for calculating the amount of and charges for Regulation Service are referenced in ISO Tariff Sections 8.6.1, 8.11, and 8.12.

The ISO will calculate the user rate for Regulation in each Zone for each Settlement Period in accordance with Section 8.12.1.

Spinning Reserve Service

Spinning Reserve Obligation:

The amount of Spinning Reserve required as a component of Operating Reserves is specified in Section 8.2.3 of the ISO Tariff.

Spinning Reserve Rates:

The formulas for calculating the amount of and charges for Spinning Reserve Service are referenced in ISO Tariff Sections 8.11.2 and 8.12.2.

The ISO will calculate the user rate for Spinning Reserve in each Zone for each Settlement Period in accordance with ISO Tariff Section 8.12.2.

Non-Spinning Reserve Service

Non-Spinning Reserve Obligation:

The amount of Non-Spinning Reserve required as a component of Operating Reserves is specified in Section 8.2.3.

Non-Spinning Reserve Rates:

The formulas for calculating the amount of and charges for Non-Spinning Reserve Service are referenced in ISO Tariff Sections 8.11.3 and 8.12.3.

The ISO will calculate the user rate for Non-Spinning Reserve in each Zone for each Settlement Period in accordance with ISO Tariff Section 8.12.3.

Replacement Reserves

The formulas for calculating the amount of and charges for Replacement Reserve Service are referenced in ISO Tariff Sections 8.11.3A and 8.12.3A.

Black Start Capability

The user rate per unit of purchased Black Start capability for each Settlement Period will be calculated in accordance with ISO Tariff Section 8.12.5.

Imbalance Energy Charges

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

Replacement Reserve Charge

The Replacement Reserve Charge will be calculated in accordance with ISO Tariff Sections 8.12.3A and 11.2.4.1.

Unaccounted for Energy

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

Transmission Losses Imbalance Charges

Transmission Losses for each hour will be calculated in accordance with ISO Tariff Sections 27.2.1.2.

Access Charges

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

Usage Charges

The amount payable by Scheduling Coordinators is determined in accordance with ISO Tariff Section 27.1.2.1.4. Usage Charges will be calculated in accordance with ISO Tariff Section 27.1.2.1.

Default Usage Charge

The Default Usage Charge will be used in accordance with ISO Tariff Section 27.1.2.1.

Grid Operations Charge for Intra-Zonal Congestion

Intra-Zonal Congestion during the initial period of operation will be managed in accordance with ISO Tariff Sections 27.1.1.6.1 and 27.1.1.6.2.

Wheeling Access Charges

The Wheeling Access Charge for transmission service is set forth in Section 26.1.4.1 of the ISO Tariff and Appendix II of the TO Tariffs.

Charge for Failure to Conform to Dispatch Instructions

The Charge for Failure to Conform to Dispatch Instructions will be determined in accordance with ISO Tariff Section 34.8.

Reliability Must-Run Charge

The Reliability Must-Run Charge will be determined in accordance with ISO Tariff Section 30.6.1.1.

FERC Annual Charge Recovery Rate

The FERC Annual Charge Recovery Rate will be determined in accordance with ISO Tariff Section 11.2.11.

ISO TARIFF APPENDIX F
Schedule 3
Access Charge

1. Objectives and Definitions

1.1 Objectives

- (a)** The Access Charge will remain utility-specific until a New Participating TO executes the Transmission Control Agreement, at which time the Access Charge will change as discussed below.
- (b)** The Access Charge is the charge assessed for using the ISO Controlled Grid. It consists of three components, the High Voltage Access Charge (HVAC), the Transition Charge and the Low Voltage Access Charge (LVAC).
- (c)** The HVAC ultimately will be based on one ISO Grid-wide rate. Initially, the HVAC will be based on TAC Areas, which will transition 10% per year to the ISO Grid-wide rate. In the first year after the Transition Date described in Section 4.2 of this Schedule 3, the HVAC will be a blend based on 10% ISO Grid-wide and 90% TAC Area.
- (d)** New High Voltage Facility additions and capital additions to Existing High Voltage Facilities will be immediately included in the ISO Grid-wide component of the HVAC. The Transmission Revenue Requirement for New High Voltage Facilities will not be included in the calculation of the Transition Charge.
- (e)** The LVAC will remain utility-specific and will be determined by each Participating TO. The LVAC of Non-Load-Serving Participating TOs may also be project specific. Each Participating TO will charge for and collect the LVAC, subject to Section 26.1 of the ISO Tariff and Section 13 of this Schedule 3.
- (f)** The cost-shift associated with transitioning from utility-specific rates to one ISO Grid-wide rate will be mitigated in accordance with the ISO Tariff, including this schedule.

1.2 Definitions

(a) Master Definition Supplement

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

(b) Special Definitions for this Appendix

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

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

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

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

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

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

All UDCs and MSS Operators in a PTO Service Territory serving Gross Loads directly connected to the transmission facilities or Distribution System of a UDC or MSS Operator in a PTO Service Territory shall pay to the ISO a charge for transmission service on the High Voltage Transmission Facilities included in the ISO Controlled Grid. The charge will be based on the High Voltage Access Charge applicable to the TAC Area in which the point of delivery is located and the applicable Transition Charge. A UDC or MSS Operator that is also a Participating TO shall pay, or receive payment of, if applicable, the difference between (i) the High Voltage Access Charge and Transition Charge applicable to its transactions as a UDC or MSS Operator; and (ii) the disbursement of High Voltage Access Charge revenues to which it is entitled pursuant to Section 26.1.3 of the ISO Tariff.

3. TAC Areas.

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

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

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

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

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

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

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

4. Transition Date

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

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

4.3 Application to Additional TAC Areas. For any TAC Areas other than those specified in Section 4.2 of this Schedule 3, created after the Transition Date, including any TAC Area created as a result of the application of Section 3.7 of this Schedule 3, whether and over what period the applicable High Voltage Access Charge shall transition to an ISO Grid-wide charge shall be determined by the ISO Governing Board.¹

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

4.5 Conversion of Existing Rights. During the process by which a New Participating TO executes the Transmission Control Agreement, the ISO and potential New Participating TO that has an obligation to serve Load shall determine the amount of FTRs to be allocated to the New Participating TO for each Existing Right that the New Participating TO converts to Converted Rights. In making that determination, the ISO will consider the amount of contracted transmission capacity, the firmness of the contracted transmission capacity, and other characteristics of the contracted transmission capacity to determine the amount of FTRs to be given to the New Participating TO in accordance with Section 36.4.3 of the ISO Tariff.

5. Determination of the Access Charge.

5.1 The Access Charge consists of a High Voltage Access Charge (HVAC) that is based on a TAC Area component and an ISO Grid-wide component, a Transmission Charge, and a Low Voltage

Access Charge (LVAC) that is based on a utility-specific rate established by each Participating TO in accordance with its TO Tariff.

- 5.2** Each Participating TO will develop, in accordance with Section 6 of this Schedule 3, a High Voltage Transmission Revenue Requirement (HVTRR_{PTO}) consisting of a Transmission Revenue Requirement for Existing High Voltage Facility (EHVTRR_{PTO}) and a Transmission Revenue Requirement for New High Voltage Facility (NHVTRR_{PTO}). The HVTRR_{PTO} includes the TRBA adjustment described in Section 6.1 of this Schedule 3.
- 5.3** The Gross Load amount in MWh shall be established by each Participating TO and filed at FERC with each Participating TO's Transmission Revenue Requirement (GL_{PTO}).
- 5.4** The HVAC applicable to each UDC or MSS Operator serving Gross Load in the PTO Service Territory, shall be based on a TAC Area component (HVAC_A) and an ISO Grid-wide component (HVAC_I).

$$\text{HVAC} = \text{HVAC}_A + \text{HVAC}_I$$

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

$$\text{ETRR}_A = \sum \text{EHVTRR}_{\text{PTO}}$$

$$\text{GL}_A = \sum \text{GL}_{\text{PTO}}$$

$$\text{HVAC}_A = (\text{ETRR}_A * \%TA) / \text{GL}_A$$

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

$$\text{ETRR}_I = \sum \text{ETRR}_A * \%IGW$$

$$\text{HVAC}_I = (\text{ETRR}_I + \text{NTRR}) / \sum \text{GL}_A$$

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

- 5.7** The Transition Charge shall be calculated separately for each Participating TO by dividing (i) the net difference between (1) the Participating TO's payment responsibility, if any, under Section 26.5 of the ISO Tariff and Section 7 of this Schedule 3; and (2) the amount, if any, payable to the Participating TO in accordance with Section 26.5 of the ISO Tariff and Section 7 of this Schedule 3; by (ii) the total of all forecasted Gross Load in the PTO Service Territory of the Participating TO, including the UDC and/or MSS Operator. If greater than zero, the

Transition Charge shall be collected with the High Voltage Access Charge. If less than zero, the Transition Charge shall be credited with the High Voltage Access Charge. The amount of each Participating TO's NHVTRR shall not be included in the Transition Charge calculation.

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

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

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

6. High Voltage Transmission Revenue Requirement.

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

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

- (b) the annual high voltage TRBA adjustment, which shall be based on the principal balance in the high voltage TRBA as of September 30 and shall be calculated as a dollar amount based on the projected Transmission Revenue Credits as adjusted for the true up of the prior year's difference between projected and actual credits. A Non-Load-Serving Participating TO shall include any over- or under-recovery of its annual High Voltage Transmission Revenue Requirement in its high voltage TRBA. If the annual high voltage TRBA adjustment involves only a partial year of operations, the Non-Load-Serving Participating TO's over- or under-recovery shall be based on a partial year revenue requirement, calculated by multiplying the Non-Load-Serving Participating TO's High Voltage Transmission Revenue Requirement by the number of days the High Voltage Transmission Facilities were under the ISO's Operational Control divided by the number of days in the year.

7. Limitation

- (a) During each year of the transition period described in this Schedule 3, the increase in the total payment responsibility applicable to Gross Loads in the PTO Service Territory of an Original Participating TO attributable to the total for the year of (i) the amount applicable for the Original Participating TO under Section 26.5 of the ISO Tariff; plus (ii) the amount applicable to the implementation of the High Voltage Access Charge shall not exceed the amount specified in paragraph (b) of this section. This limitation shall be calculated individually for each Original Participating TO, provided that, if the net effect of clauses (i) and (ii) of this paragraph is positive for one or more Original Participating TOs for any year, the combined net effect shall be allocated among all Original Participating TOs in proportion to the amounts specified in paragraph (b) of this section. This limitation shall be applied by the ISO's calculation annually of amounts payable by New Participating TOs to Original Participating TOs such that the combined effect of clauses (i) and (ii) of this paragraph, and the payments received by each Original Participating TO shall not exceed the amounts specified in paragraph (b) of this section. The amount receivable by the Original Participating TO from the New Participating TOs to implement the limitation in paragraph (b) of this section, shall be credited through the Transition Charge established pursuant to Section 5.7 of this Schedule 3. Payment responsibility under this section, if any, shall be allocated among New Participating TOs in proportion to their TAC Benefits.
- (b) The maximum annual amounts for Original Participating TO shall be as follows:
 - (i) For Pacific Gas and Electric Company and Southern California Edison Company, the maximum annual amount shall be thirty-two million dollars (\$32,000,000.00) each; and
 - (ii) For San Diego Gas & Electric Company, the maximum annual amount shall be eight million dollars (\$8,000,000.00).

8. Updates to High Voltage Access Charges.

- 8.1** High Voltage Access Charges and High Voltage Wheeling Access Charges shall be adjusted: (1) on January 1 and July 1 of each year when necessary to reflect the addition of any New Participating TO and (2) on the date FERC makes effective a change to the High Voltage Transmission Revenue Requirements of any Participating TO. Using the High Voltage

Transmission Revenue Requirement accepted or authorized by FERC, consistent with Section 9 of this Schedule 3, for each Participating TO, the ISO will recalculate on a monthly basis the High Voltage Access Charge and Transition Charge applicable during such period. Revisions to the Transmission Revenue Balancing Account adjustment shall be made effective annually on January 1 based on the principal balance in the TRBA as of September 30 of the prior year and a forecast of Transmission Revenue Credits for the next year.

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

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

8.4

9. Approval of Updated High Voltage Revenue Requirements

9.1 Participating TOs will make the appropriate filings at FERC to establish their Transmission Revenue Requirements for their Low Voltage Access Charges and the applicable High Voltage Access Charges, and to obtain approval of any changes thereto. All such filings with the FERC will include a separate appendix that states the HVTRR, LVTRR (if applicable) and the appropriate Gross Load data and other information required by the FERC to support the Access Charges. The Participating TO will provide a copy of its filing to the ISO and the other Participating TOs in accordance with the notice provisions in the Transmission Control Agreement.

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

filing to the ISO and the other Participating TOs in accordance with the notice provisions in the Transmission Control Agreement.

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

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

- (a) the amount determined in accordance with Section 26.1.2 of the ISO Tariff ("Billed HVAC/TC");
- (b)
 - (i) for a Participating TO that is a UDC or MSS Operator and has Gross Load in its TO Tariff in accordance with Appendix F, Schedule 3, Section 9, then calculate the amount each UDC or MSS Operator would have paid and the Participating TO would have received by multiplying the High Voltage Utility-Specific Rates for the Participating TO whose High Voltage Facilities served such UDC and MSS Operator times the actual Gross Load of such UDCs and MSS Operators ("Utility-specific HVAC"); or
 - (ii) for a Non-Load-Serving Participating TO, then calculate the Non-Load-Serving Participating TO's portion of the total Billed HVAC/TC in subsection (a) based on the ratio of the Non-Load-Serving Participating TO's High Voltage Transmission Revenue Requirement to the sum of all Participating TOs' High Voltage Revenue Requirements.
- (c) if the total Billed HVAC/TC in subsection (a) received by the ISO less the total dollar amounts calculated in Utility-specific HVAC in subsection (b)(i) and subsection (b)(ii) is different from zero, the ISO shall allocate the positive or negative difference among those Participating TOs that are subject to the calculations in subsection (b)(i) based on the ratio of each Participating TO's High Voltage Transmission Revenue Requirement to the sum of all of those Participating TOs' High Voltage Transmission Revenue Requirements that are subject to the calculations in subsection (b)(i). This monthly distribution amount is the "HVAC Revenue Adjustment";
- (d) the sum of the HVAC revenue share determined in subsection (b) and the HVAC Revenue Adjustment in subsection (c) will be the monthly disbursement to the Participating TO.

10.2 If the same entity is both a Participating TO and a UDC or MSS Operator, then the monthly High Voltage Access Charge and Transition Charge amount billed by the ISO will be the charges payable by the UDC or MSS Operator in accordance with Section 26.1.2 of the ISO Tariff less the disbursement determined in accordance with Section 10.1(d). If this difference is negative, that amount will be paid by the ISO to the Participating TO.

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

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

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

12.1 Division of Costs:

(a) Substations

Costs for substations and substation equipment, including transformers:

- (i) If the Participating TO has substation TRR information by facility and voltage, then the TRR for facilities and equipment at or above 200 kV should be allocated to the HVTRR and the TRR for facilities and equipment below 200 kV should be allocated to the LVTRR;
- (ii) If the Participating TO has substation TRR information by facility but not by voltage, then the TRR for facilities and equipment should be allocated to the HVTRR and to the LVTRR based on the ratio of gross substation investment allocated to HVTRR to gross substation investment allocated to LVTRR pursuant to Section 12.1(a)(i); or
- (iii) If the Participating TO does not have substation TRR information by facility or voltage, then the TRR for facilities and equipment should be allocated to the HVTRR and to the LVTRR based on the Participating TO's transmission system-wide gross plant ratio. The system-wide gross plant ratio is determined once the costs that can be split between High Voltage and Low Voltage for all facilities has been developed in accordance with Sections 12.1(a) through (c), then the resulting cost ratio between High Voltage and Low Voltage shall be used as the system-wide gross plant ratio.
- (iv) Costs of transformers that step down from high voltage (200 kV or above) to low voltage, to the extent the Participating TO does not have the revenue requirement information available on a voltage basis, should be allocated consistent with the procedures for substations addressed above.

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

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

rights-of-way for towers that have both High Voltage and Low Voltage wires should be allocated two-thirds to the HVTRR component and one-third to the LVTRR.

- (c) Operation and Maintenance, Transmission Wages & Salaries, Taxes, Depreciation and Amortization, and Capital Costs
If the Participating TO can delineate costs for transmission operations and maintenance (O&M), transmission wages and salaries, taxes, depreciation and amortization, or capital costs on a voltage basis, the costs shall be applied on a bright-line voltage basis. If the costs for O&M, transmission wages and salaries, taxes, depreciation and amortization, or capital costs, are not available on voltage levels, the allocation to the HVTRR and the LVTRR should be based on the Participating TO's system-wide gross plant ratio defined in Section 12.1(a).
- (d) Existing Transmission Contracts
If the take-out point for the Existing Contract is a High Voltage Transmission Facility, the Existing Contract revenue will be credited to the HVTRR of the Participating TO receiving such revenue. Similarly, the Participating TO that is paying charges under such an Existing Contract may include the costs in its HVTRR. If the take-out point for the Existing Contract is a Low Voltage Transmission Facility, the Existing Contract revenue will be credited to the HVTRR and the LVTRR of the receiving Participating TO based on the ratio of the Participating TO's HVTRR to its LVTRR, prior to any adjustments for such revenues. The Participating TO that is paying the charges under the Existing Contract will include the costs in its HVTRR and LVTRR in the same ratio as the revenues are recognized by the Participating TO receiving the payments.
- (e) Division of the TRBAA between HVTRR and LVTRR
- (i) Wheeling revenues associated with transactions exiting the ISO Controlled Grid at High Voltage Scheduling Points or Take-Out Points shall be reflected as High Voltage components;
 - (ii) Wheeling revenues associated with transactions exiting the ISO Controlled Grid at Low Voltage Scheduling Points or Take-Out Points shall be attributed between High Voltage and Low Voltage TRBAA components based on the High Voltage and Low Voltage Wheeling Access Charge rates assessed to such transactions by the ISO and/or the Participating TO;
 - (iii) Any Low Voltage Access Charge amounts paid pursuant to Section 26.1 of the ISO Tariff for the Low Voltage Transmission Facilities of a Non-Load-Serving Participating TO shall be reflected as a component of the low voltage TRBA adjustment associated with the Low Voltage Access Charge;
 - (iv) FTR revenues shall be assigned to High Voltage or Low Voltage components based on the voltage of the path related to the FTR;
 - (v) Usage Charge revenues shall be allocated between High Voltage and Low Voltage components on a gross plant basis; and
 - (vi) Other Transmission Revenue Credits shall be allocated between High Voltage and Low Voltage components on a gross plant basis.

13. Low Voltage Access Charge for a Non-Load-Serving Participating TO. Pursuant to Section 26.1 of the ISO Tariff, the provisions of this Section 13 of this Schedule 3 shall apply to a Non-Load-Serving Participating TO that has Low Voltage Transmission Facilities.

- 13.1 Low Voltage Transmission Revenue Requirement.** The Low Voltage Transmission Revenue Requirement of a Non-Load-Serving Participating TO shall be calculated separately for each individual project that includes one or more Low Voltage Transmission Facilities or shall be calculated for a group of Low Voltage Transmission Facilities if all are part of projects directly connected to the facilities of the same Participating TO(s). The Low Voltage Transmission Revenue Requirement will be determined consistent with ISO procedures posted on the ISO Home Page and shall be the sum of:
- (a) the Non-Load-Serving Participating TO's Low Voltage Transmission Revenue Requirement for the relevant Low Voltage Transmission Facility or group of facilities; and
 - (b) the annual low voltage TRBA adjustment for the relevant Low Voltage Transmission Facility or group of facilities, which shall be based on the principal balance in the low voltage TRBA as of September 30 and shall be calculated as a dollar amount based on the projected Transmission Revenue Credits as adjusted for the true up of the prior year's difference between projected and actual credits. In accordance with Section 26.1 of the ISO Tariff, the Non-Load-Serving Participating TO shall include any over- or under-recovery of its annual Low Voltage Transmission Revenue Requirement in its low voltage TRBA. If the annual low voltage TRBA adjustment involves only a partial year of operations, the Non-Load-Serving Participating TO's over- or under-recovery shall be based on a partial year revenue requirement, calculated by multiplying the Non-Load-Serving Participating TO's Low Voltage Transmission Revenue Requirement by the number of days the Low Voltage Transmission Facilities were under the ISO's Operational Control divided by the number of days in the year.

- 13.2 Updates to Low Voltage Access Charges.** Unless otherwise agreed by the affected Participating TOs, a Non-Load-Serving Participating TO shall adjust its Low Voltage Access Charges and Low Voltage Wheeling Access Charges (1) when necessary to reflect any new transmission addition directly connecting a Participating TO to the Low Voltage Transmission Facilities of the Non-Load-Serving Participating TO; (2) on the date FERC makes effective a change to the Low Voltage Transmission Revenue Requirement of the Non-Load-Serving Participating TO; and (3) on the date FERC makes effective a change to Gross Load of a Participating TO directly connected to the Non-Load-Serving Participating TO. Using the Low Voltage Transmission Revenue Requirement accepted or authorized by FERC, consistent with Section 9 of this Schedule 3, for the Non-Load-Serving Participating TO, the ISO will recalculate on a monthly basis the Low Voltage Access Charge applicable during such period. Revisions to the low voltage TRBA adjustment shall be made effective annually on January 1 based on the principal balance in the low voltage TRBA as of September 30 of the prior year and a forecast of Transmission Revenue Credits for the next year.

For service provided by a Non-Load-Serving Participating TO following the Transition Date, any refund associated with a Non-Load-Serving Participating TO's Transmission Revenue Requirement that has been accepted by FERC, subject to refund, shall be provided as ordered by FERC. Such refund shall be invoiced separately from the Market Invoice.

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

13.3 Approval of Updated Low Voltage Transmission Revenue Requirement. A Non-Load-Serving Participating TO will make the appropriate filings at FERC to establish its Transmission Revenue Requirement for its Low Voltage Access Charge, and to obtain approval of any changes thereto. All such filings with the FERC will include a separate appendix that states the LVTRR and other information required by the FERC to support the Low Voltage Access Charge. The Non-Load-Serving Participating TO will provide a copy of its filing to the ISO and the other Participating TOs in accordance with the notice provisions in the Transmission Control Agreement.

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

13.4 Disbursement of Low Voltage Access Charge Revenues. Unless otherwise agreed by the affected Participating TOs, Low Voltage Access Charge revenues of a Non-Load-Serving Participating TO shall be calculated for disbursement to that Non-Load-Serving Participating TO on a monthly basis as the sum of Low Voltage Access Charges billed by the ISO to the UDCs or MSS Operators of Participating TOs pursuant to Section 26.1 of the ISO Tariff.

13.5 Payment of Low Voltage Access Charge. Notwithstanding the separate accounting for the Low Voltage Access Charge specified in Section 26.1 of ISO Tariff and this Section 13 of this Schedule 3, if the same entity is both a Participating TO and a UDC or MSS Operator, then the monthly High Voltage Access Charge and Transition Charge amount, and any Low Voltage Access Charge amount pursuant to this Section 13 of this Schedule 3, billed by the ISO will be the charges payable by the UDC or MSS Operator in accordance with Sections 26.1.2 and 26.1 of the ISO Tariff less the disbursement determined in accordance with Section 10.1(d) of this Schedule 3. If this difference is negative, that amount will be paid by the ISO to the Participating TO.

ISO TARIFF APPENDIX F
Schedule 4

Participating Intermittent Resources Forecasting Fee

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

Participating Intermittent Resources Process Fee

A Process Fee charge shall be assessed, for each calendar quarter, to each Exporting Participating Intermittent Resource that exported Energy in the quarter. On an annualized basis, the aggregate quarterly charges shall total to \$10,000. The charge is not volumetric, and shall be calculated as follows:

$$(\$10,000/4)/N = \$\text{quarterly charge}$$

N = number of Participating Intermittent Resources exporting Energy in the quarter

Participating Intermittent Resources Export Fee

A Participating Intermittent Resources Export Fee shall be assessed to Exporting Participating Intermittent Resources each calendar quarter. The Participating Intermittent Resources Export Fee shall be calculated as the product of (1) the sum of all settlement costs avoided by Participating Intermittent Resources for the preceding calendar quarter, or portion thereof, consisting of Charge Types 1597 [FERC Must-offer Obligation Capacity Payment System Allocation], 1697 [Tier 1 MLCC Allocation for System Needs], 1797 [Tier 1 MLCC Allocation of Resource Adequacy for System Needs], 1897 [Tier 1 MLCC Allocation of **TCPM** for System Needs], and 4487 [Allocation of Excess Cost for Instructed Energy], but excluding charges for Uninstructed Energy associated with Charge Type 4407 and Transmission Loss Obligation associated with Charge Type 4450, (2) by the ratio of the total MW/h generated by an Exporting Participating Intermittent Resource during the calendar quarter, or portion thereof (based on metered output), by the total MW/h generated by all Participating Intermittent Resources during the calendar quarter, or portion thereof (based on metered output), and (3) by the percentage of the Exporting Participating Intermittent Resource's capacity deemed exporting under EIRP 5.3 or Export Percentage.

Participating Intermittent Resources Export Fee per Participating Intermittent Resource =

Program Costs x (MW/h individual Participating Intermittent Resource/MW/h all Participating Intermittent Resources) x Export Percentage

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.

ISO TARIFF APPENDIX F
Schedule 6

TCPM SCHEDULES

Monthly TCPM Charge

The Monthly TCPM Charge shall be calculated by multiplying the monthly shaping factors by the target annual capacity price (\$86/kW-yr).

Monthly Shaping Factors

	<u>SP-15</u>	<u>NP-15/ZP-26</u>
Jan	6.7%	4.9%
Feb	5%	4.9%
Mar	5%	5.6%
Apr	5.8%	4.6%
May	6.3%	4.8%
Jun	8.3%	5.1%
Jul	15.8%	13.7%
Aug	17.5%	15.3%
Sept	11.7%	13.8%
Oct	5.8%	8.7%
Nov	6.3%	8.8%
Dec	5.8%	9.8%
Total	100%	100%

Availability

The target Availability for a resource designated under **TCPM** is 95%. Incentives and penalties for availability above and below the target are as set forth in the table below, entitled “Availability Factor Table.” The ISO will calculate availability on a monthly basis using actual availability data. The “Availability Factor” for each month shall be calculated using the following curve:

AVAILABILITY FACTOR TABLE

Availability (excluding only Scheduled Maintenance)	Capacity Payment Factor	Availability Factor
100%	3.3%	1.139
99%	3.3%	1.106
98%	3.3%	1.073
97%	2.5%	1.040
96%	1.5%	1.015
95%	-	1.000
94%	-1.5%	.985
93%	-1.5%	.970
92%	-1.5%	.955
91%	-1.5%	.940
90%	-1.5%	.925
89-80%	-1.7%*	.908-.755
79-41%	-1.9%*	.736-.014
-40%	-	0.0

*The “Capacity Payment Factor” decreases by 1.7% and 1.9% respectively for every 1% decrease in availability.

The capacity payment will be adjusted upward from the 95% Availability starting point by the positive percentages listed as the Capacity Payment Factor above, by the amounts listed for each availability factor above 95%, so that, for example, if a 97% Availability is achieved for the month (as described below), then the capacity payment for that month would be the monthly value for 95% plus an additional 4% (1.5% for the first percent Availability above 95%, and 2.5% for the second percent Availability above 95%). Reductions in capacity payment will be made correspondingly according to the Capacity Payment Factor above for monthly availability levels falling short of the 95% availability starting point.

Calculation of the Monthly PER

The ISO shall calculate the Monthly Peak Energy Rent (“Monthly PER”) as follows: immediately following the end of the month the ISO will determine all those hours during which the Reference Resource would

have been dispatched (based on Reference Resource characteristics) to provide either energy or non-spinning reserves and will calculate, on a per kW-Month basis, the total dollar amount of rent (earnings in excess of proxy unit variable costs calculated using Reference Resource unit characteristics) that would have been earned by the Reference Resource. The Reference Resource will be assumed to have been dispatched for energy in any hour in which the hourly energy price described below is greater than the Reference Resource variable cost; the ISO shall use its day ahead Non-spinning Reserve price to calculate the rent for all hours in which the Reference Resource is not assumed dispatched to provide energy (i.e., any hour where the hourly price is less than the Reference Resource variable costs).

Hourly price profiles will be determined using the shaping factors for SP-15 and NP15/ZP-26 that appear below. Hourly energy prices shall be the weighted average of: (1) the applicable zonal on/off peak day-ahead index prices set forth in Platts Megawatt Daily, shaped to hourly profiles using the factors set forth below, and (2) the applicable zonal ISO hourly average real-time energy prices. For TCPM, the index/ex post weighting will be 75/25.

The assumed heat rate of the Reference Resource will be 10,500 BTU/kWh. Variable operations and maintenance costs shall be based on the Energy Information Administration AEO Electricity Market Module Assumptions, which are currently \$3.36/MWh. An emissions allowance of \$0.71/MWh shall be used to estimate variable costs. Gas prices for the Reference Resource will be based on a daily gas price based on 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 is served from one of those three Service Areas then from the nearest of those Service Areas.

NP-15

	Mon-Fri JAN-MAY	Mon-Fri JUN-SEPT	Mon-Fri OCT-DEC	Sat JAN-MAY	Sat JUN-SEPT	Sat OCT-DEC	Sun JAN-MAY	Sun JUN-SEPT	Sun OCT-DEC
N1	1.05454758	1.00584021	0.99435526	1.43649	1.120844	1.073148	0.755403	0.759704	0.783346
N2	0.85716711	0.86062114	0.91898795	1.032749	1.092377	0.978957	0.600188	0.683139	0.701588
N3	0.75399836	0.79068297	0.92144851	0.758585	0.91744	0.921009	0.458319	0.636187	0.68291
N4	0.71058351	0.79900018	0.89479611	0.680278	0.892744	0.911836	0.444573	0.616409	0.662295
N5	0.78267681	0.8161591	0.94516384	0.630256	0.909543	0.926083	0.362844	0.5641	0.662342
N6	1.02256586	0.86829359	1.10962719	0.623168	0.709153	0.947344	0.293086	0.335463	0.707489
N7	0.75351629	0.46629678	0.84979936	0.459933	0.363102	0.835985	0.324748	0.244038	0.795325
N8	0.88610975	0.66277777	0.86218587	0.741872	0.587123	0.805198	0.576432	0.514076	0.804009
N9	0.93647065	0.72748598	0.87228518	0.967023	0.960062	0.891018	0.923411	0.756354	0.873764
N10	0.98013307	0.83355915	0.99306313	1.050452	0.998448	0.917894	1.087891	0.848836	0.970588
N11	1.05081328	0.91348904	0.97923559	1.079888	0.984474	1.02248	1.303241	0.94756	1.027355
N12	1.068781	0.96178966	0.98802244	1.086984	1.03194	0.961419	1.304385	1.158765	1.097895
N13	1.06644102	1.07695356	0.99576872	1.083005	1.00669	0.992817	1.283414	1.168292	1.059999
N14	1.09775977	1.22226563	1.06440722	1.072448	1.0038	1.04347	1.281892	1.283789	1.110655
N15	1.09364901	1.38229366	1.11766171	1.053707	1.124805	1.05608	1.263359	1.309879	1.150637
N16	1.0841716	1.44680734	1.14665908	1.048562	1.135933	1.056274	1.316946	1.317595	1.140864
N17	1.02358917	1.3710053	1.1033917	1.049893	1.362503	1.087482	1.311524	1.567664	1.232842
N18	0.9788975	1.21057642	0.95748393	1.049616	1.327635	1.081109	1.30229	1.71578	1.406331
N19	0.94570613	1.03868542	1.10717179	1.036387	1.126072	1.09328	1.321985	1.367096	1.419466
N20	0.96174495	0.91022871	1.13578926	1.048527	0.943973	1.193558	1.393578	1.139089	1.494944
N21	1.11577915	0.94038191	1.03355639	1.133815	1.001619	1.076201	1.778309	1.551657	1.39373
N22	0.95643767	0.8354037	0.79351865	1.037886	1.04182	0.885733	1.392837	1.473652	1.062792
N23	1.56132501	1.66415743	1.17445625	1.670367	1.287221	1.205472	1.150247	1.253671	0.972486
N24	1.25713576	1.19524538	1.04116487	1.168106	1.070678	1.036151	0.769097	0.787205	0.786348

SP-15

Weekday January through June

Hour	January	February	March	April	May	June
1	0.9	0.97	1.018	0.973	0.951	0.945
2	0.858	0.908	0.896	0.902	0.839	0.826
3	0.839	0.885	0.828	0.849	0.756	0.745
4	0.836	0.876	0.821	0.824	0.717	0.727
5	0.887	0.977	0.948	0.878	0.879	0.794
6	1.155	1.11	1.068	1.008	1.086	0.908
7	0.898	0.933	0.79	0.779	0.6	0.474
8	1.007		0.892	0.92	0.778	0.613
9	1.017	1.004	0.941	0.94	0.875	0.711
10	1.011	1.019	0.983	0.991	0.976	0.806
11	0.976	0.994	1.027	1.024	1.035	1.04
12	0.98	0.99	1.038	1.038	1.074	1.087
13	0.972	0.994	1.055	1.075	1.126	1.127
14	0.983	0.984	1.06	1.098	1.193	1.201
15	0.955	0.963	1.039	1.072	1.175	1.247
16	0.886	0.932	0.994	1.031	1.147	1.26
17	0.869	0.905	0.856	0.965	1.089	1.216
18	1.171	1.044	0.983	0.914	0.997	1.12
19	1.158	1.136	1.167	0.944	0.882	1.012
20	1.075	1.067	1.082	1.06	0.965	0.965
21	1.059	1.06	1.048	1.14	1.153	1.119
22	0.941	0.975	0.946	1.009	0.935	0.999
23	1.371	1.213	1.305	1.383	1.536	1.733
24	1.153	1.082	1.117	1.183	1.235	1.322

Saturday January through June

Hour	January	February	March	April	May	June
1	0.999	1.073	1.104	0.982	1.071	1.064
2	0.905	0.971	0.922	0.917	0.957	0.882
3	0.899	0.962	0.899	0.883	0.839	0.828
4	0.875	0.93	0.868	0.855	0.814	0.803
5	0.91	0.917	0.88	0.904	0.826	0.788
6	0.972	0.983	0.88	0.969	0.836	0.818
7	0.795	0.854	0.777	0.761	0.603	0.411
8	0.874	0.906	0.844	0.848	0.728	0.522
9	0.992	1.015	0.932	0.929	0.885	0.645
10	1.028	1.037	0.997	0.999	0.984	0.806
11	1.005	1.048	1.027	1.042	1.047	1.055
12	1.005	1.033	1.027	1.053	1.069	1.089
13	0.978	1.009	1.032	1.054	1.096	1.122
14	0.939	0.967	0.983	1.042	1.093	1.165
15	0.882	0.939	0.963	1.022	1.086	1.203
16	0.871	0.892	0.949	0.973	1.071	1.255
17	0.945	0.899	0.934	0.962	1.063	1.254
18	1.196	1.03	1.016	0.912	1.011	1.17
19	1.185	1.155	1.199	1.047	0.934	1.076
20	1.141	1.076	1.165	1.113	1.058	0.984
21	1.114	1.104	1.133	1.165	1.237	1.143
22	1.04	1.036	1.022	1.076	1.035	1.102
23	1.323	1.117	1.331	1.327	1.478	1.622
24	1.117	1.038	1.126	1.164	1.18	1.194

Sunday January through June

Hour	January	February	March	April	May	June
1	0.897	0.85	0.787	0.869	0.794	0.854
2	0.806	0.792	0.762	0.771	0.7	0.7
3	0.745	0.802	0.716	0.732	0.628	0.622
4	0.706	0.802	0.695	0.722	0.594	0.519
5	0.707	0.794	0.707	0.696	0.623	0.469
6	0.782	0.793	0.72	0.671	0.585	0.445
7	0.818	0.873	0.691	0.711	0.471	0.372
8	0.882	0.912	0.819	0.826	0.635	0.522
9	0.975	1.007	0.945	0.926	0.757	0.631
10	1.035	1.073	1.029	1.022	0.87	0.75
11	1.03	1.065	1.069	1.059	1.059	1.019
12	1.049	1.083	1.112	1.101	1.126	1.141
13	1.043	1.065	1.147	1.118	1.176	1.268
14	1.029	1.061	1.141	1.127	1.239	1.341
15	1.003	1.033	1.11	1.097	1.279	1.44
16	0.98	1.004	1.115	1.11	1.265	1.482
17	1.039	1.006	1.091	1.052	1.336	1.526
18	1.324	1.161	1.179	1.033	1.363	1.403
19	1.37	1.305	1.421	1.191	1.231	1.321
20	1.338	1.248	1.366	1.35	1.327	1.242
21	1.286	1.213	1.288	1.469	1.471	1.381
22	1.166	1.144	1.191	1.318	1.263	1.291
23	1.079	1.066	1.082	1.127	1.239	1.339
24	0.912	0.869	0.816	0.922	0.938	0.92

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
 FERC ELECTRIC TARIFF
 THIRD REPLACEMENT VOLUME NO. II

First Revised Sheet No. 755F
 Superseding Original Sheet No. 755F

Weekday July through December

Hour	July	August	Septemb er	October	Novembe	Decembe
					r	r
1	1.002	0.994	1.083	1.04	0.966	1.001
2	0.89	0.903	0.92	0.879	0.834	0.883
3	0.81	0.835	0.782	0.751	0.708	0.814
4	0.767	0.813	0.749	0.69	0.723	0.805
5	0.796	0.841	0.822	0.829	0.879	0.903
6	0.914	0.982	1.049	1.08	1.266	1.088
7	0.493	0.547	0.634	0.763	0.899	0.895
8	0.632	0.637	0.751	0.858	0.98	1.012
9	0.728	0.743	0.796	0.837	0.977	1.012
10	0.837	0.822	0.859	0.9	0.957	1.005
11	0.983	0.999	0.966	0.96	0.959	0.983
12	1.051	1.056	1.013	0.975	0.943	0.93
13	1.097	1.106	1.078	1.013	0.933	0.906
14	1.183	1.179	1.15	1.076	0.946	0.894
15	1.257	1.24	1.213	1.147	0.93	0.87
16	1.284	1.264	1.236	1.152	0.93	0.863
17	1.258	1.235	1.197	1.128	0.989	0.967
18	1.183	1.149	1.11	1.019	1.221	1.194
19	1.065	1.05	1.052	1.073	1.207	1.213
20	0.982	1.05	1.051	1.122	1.137	1.174
21	1.034	1.028	1.031	1.048	1.046	1.085
22	0.935	0.895	0.876	0.927	0.936	0.998
23	1.623	1.493	1.371	1.497	1.427	1.316
24	1.197	1.14	1.223	1.235	1.2	1.191

Saturday July through December

Hour	July	August	Septemb er	October	Novembe	Decembe
					r	r
1	1.065	1.107	1.206	1.202	1.145	1.108
2	0.952	0.984	1.046	1.038	0.952	0.982
3	0.88	0.939	0.919	0.871	0.784	0.86
4	0.85	0.847	0.844	0.786	0.753	0.843
5	0.871	0.832	0.863	0.778	0.821	0.875
6	0.841	0.882	0.848	0.885	1.014	0.909
7	0.451	0.494	0.542	0.609	0.745	0.76
8	0.539	0.56	0.622	0.63	0.893	0.845
9	0.682	0.679	0.733	0.663	0.961	0.997
10	0.778	0.788	0.814	0.943	0.977	1.015
11	0.956	0.919	0.971	1.017	1.027	1.022
12	1.019	1.029	1.045	1.039	1.002	1
13	1.087	1.103	1.125	1.068	0.924	0.984
14	1.16	1.183	1.149	1.108	0.91	0.921
15	1.236	1.252	1.194	1.105	0.889	0.818
16	1.284	1.298	1.216	1.124	0.89	0.775
17	1.301	1.252	1.205	1.073	1.003	1.006
18	1.251	1.215	1.17	1.103	1.237	1.212
19	1.132	1.097	1.086	1.157	1.228	1.211
20	1.029	1.111	1.097	1.208	1.172	1.173
21	1.076	1.077	1.074	1.176	1.1	1.139
22	1.02	0.943	0.957	0.976	1.041	1.124
23	1.395	1.358	1.185	1.389	1.41	1.291
24	1.147	1.07	1.09	1.071	1.12	1.133

Sunday July through December

Hour	July	August	Septemb er	October	Novembe	Decembe
					r	r
1	0.834	0.81	0.884	0.868	0.916	0.889
2	0.739	0.729	0.688	0.685	0.788	0.809
3	0.679	0.672	0.527	0.562	0.613	0.698
4	0.655	0.653	0.489	0.574	0.576	0.634
5	0.61	0.657	0.463	0.558	0.586	0.68
6	0.496	0.647	0.512	0.613	0.62	0.747
7	0.445	0.549	0.527	0.573	0.666	0.777
8	0.587	0.618	0.619	0.697	0.776	0.848
9	0.719	0.704	0.713	0.708	0.997	0.985
10	0.877	0.854	0.901	0.829	1.103	1.052
11	1.005	0.991	1.035	1.102	1.143	1.067
12	1.106	1.154	1.178	1.183	1.151	1.052
13	1.167	1.151	1.318	1.154	1.125	1.029
14	1.254	1.25	1.353	1.24	1.138	0.993
15	1.339	1.358	1.347	1.252	1.085	0.929
16	1.432	1.43	1.354	1.272	1.063	0.92
17	1.447	1.467	1.375	1.235	1.279	1.146
18	1.383	1.398	1.372	1.407	1.346	1.351
19	1.301	1.278	1.314	1.481	1.395	1.387
20	1.194	1.243	1.336	1.517	1.296	1.317
21	1.336	1.322	1.359	1.477	1.217	1.279
22	1.217	1.171	1.24	1.18	1.097	1.241
23	1.221	1.063	1.171	1.115	1.096	1.188
24	0.956	0.843	0.923	0.735	0.927	0.983

ISO TARIFF APPENDIX G

Must-Run Agreements

To be filed upon settlement

ISO TARIFF APPENDIX H
Methodology for Developing the Weighted Average Rate for Wheeling Service

ISO TARIFF APPENDIX H
Methodology for Developing the Weighted Average Rate
for Wheeling Service

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

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

Where:

- WBAC = Weighted-average Wheeling Access Charge for each ISO Scheduling Point
- P_n = The applicable Wheeling Access Charge rate for a TAC Area or Participating TO_n in \$/kWh as set forth in Section 26.1.4 of the ISO Tariff and Section 5 of the TO Tariff.
- Q_n = The Available Transfer Capacity (in MW), whether from transmission ownership or contractual entitlements, of each Participating TO_n for each ISO Scheduling Point which has been placed within the ISO Controlled Grid. Available Transfer Capacity shall not include capacity associated with Existing Rights of a Participating TO as defined in Section 16.2 of the ISO Tariff.
- n = the number of Participating TOs from 1 to n

ISO TARRF APPENDIX I
ISO Congestion Management Zones

ISO TARIFF APPENDIX I
ISO Congestion Management Zones

1. **Active Zones**
 - A. Northern Zone (NP15)
 - B. Central Zone (ZP26)
 - C. Southern Zone (SP15)

2. **Inactive Zones**
 - A. Humboldt Zone
 - B. San Francisco Zone

Note: The ISO's Initial Congestion Management Zones were described in the Joint Application of the IOUs for Authorization to Convey Operational Control of Designated Jurisdictional Facilities to an ISO filed April 29, 1996, Docket No. EC96-19-000.

ISO TARIFF APPENDIX J
End-Use Meter Standards and Capabilities

ISO TARIFF APPENDIX J

End-Use Meter Standards and Capabilities

End-Use Meter Standards & Capabilities Part A

End Use Meter Standards. All metering shall be of a revenue class metering accuracy in accordance with the ANSI C12 standards on metering and any other requirements of the relevant UDC or Local Regulatory Authority that may apply. Such requirements may apply to meters, current transformers and potential transformers, and associated equipment. ANSI C12 metering standards include the following:

ANSI C12.1 - American National Standard Code For Electricity Metering

ANSI C12.4 - American National Standard For Mechanical Demand Registers

ANSI C12.5 - American National Standard For Thermal Demand Meters

ANSI C12.6 - American National Standard For Marking And Arrangement Of Terminals For Phase-Shifting Devices Used In Metering

ANSI C12.7 - American National Standard For Watt-hour Meter Sockets

ANSI C12.8 - American National Standard For Test Blocks And Cabinets For installation Of Self-Contained A-Base Watt-hour Meters

ANSI C12.9 - American National Standard For Test Switches For Transformer-Rated Meters

ANSI C12.10 - American National Standard For Electromechanical Watt-hour Meters

ANSI C12.11 - American National Standard For Instrument Transformers For Revenue Metering, 10 kV BIL Through 350 kV BIL

ANSI C12.13 - American National Standard For Electronic Time-Of -Use Registers For Electricity Meters

ANSI C12.14 - American National Standard For Magnetic Tape Pulse Recorders For Electricity Meters

ANSI C12.15 - American National Standard For Solid-State Demand Registers For Electromechanical Watt-hour Meters

ANSI C12.16 - American National Standard For Solid-State Electricity Meters

ANSI C12.17 - American National Standard For Cartridge-Type Solid-State Pulse Recorders For Electricity Metering

ANSI C12.18 - American National Standard For Protocol Specification For ANSI Type 2 Optical Port

Part B

PARTICIPATING SELLERS METER STANDARDS AND CAPABILITIES

ISO TARIFF APPENDIX K
Ancillary Service Requirements Protocol

ISO TARIFF APPENDIX K
Ancillary Service Requirements Protocol

PART A
CERTIFICATION FOR REGULATION

A 1 A Generator wishing to provide Regulation as an Ancillary Service from a Generating Unit whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following operating characteristics and technical requirements in order to be certified by the ISO to provide Regulation service unless granted a temporary exemption by the ISO in accordance with criteria which the ISO shall publish on the ISO's internet "Home Page;"

A 1.1 **Operating Characteristics**

A 1.1.1 the rated capacity of the Generating Unit must be 1 MW or greater unless the Generating Unit is participating in an aggregation arrangement approved by the ISO;

A 1.1.2 the maximum amount of Regulation to be offered must be reached within a period that may range from a minimum of 10 minutes to a maximum of 30 minutes, as such period may be specified by the ISO and published on the ISO's internet "Home Page;"

A 1.2 **Technical Requirements**

A 1.2.1 **Control**

A 1.2.1.1 a direct, digital, unfiltered control signal generated from the ISO EMS through a standard ISO direct communication and direct control system, must meet the minimum performance standards for communications and control which will be developed and posted by the ISO on its internet "Home Page;"

A 1.2.1.2 the Generating Unit power output response (in MW) to a control signal must meet the minimum performance standards for control and unit response which will be developed and posted by the ISO on its internet "Home Page." As indicated by the Generating Unit power output (in MW), the Generating Unit must respond immediately, without manual Generating Unit operator intervention, to control signals and must sustain its specified ramp rate, within specified Regulation limits, for each minute of control response (MW/minute);

A 1.2.2 **Monitoring:**

the Generating Unit must have a standard ISO direct communication and direct control system to send signals to the ISO EMS to dynamically monitor, at a minimum the following:

- A 1.2.2.1** actual power output (MW);
- A 1.2.2.2** high limit, low limit and rate limit values as selected by the Generating Unit operator; and
- A 1.2.2.3** in-service status indication confirming availability of Regulation service.
- A 1.2.3** **Voice Communications:**
- ISO approved primary and back-up voice communication must be in place between the ISO Control Center and the operator controlling the Generating Unit at the generating site and between the Scheduling Coordinator and the operator. The primary dedicated voice communication between the ISO Control Center and the operator controlling the Generating Unit at the generating site must be digital voice communication, as provided by a standard ISO direct communication and direct control system; and
- A 1.3** the communication and control system and the Generating Unit must pass a qualification test to demonstrate the overall ability to provide Regulation meeting the performance requirements of the ASRP for Regulation.
- A 2** A Generator wishing to be considered for certification for Regulation service by the ISO must make a written request to the ISO, giving details of the technical capability of the Generating Units concerned and identifying the Scheduling Coordinator through whom the Generator intends to offer Regulation service. The Generator shall at the same time send a copy of its request to that Scheduling Coordinator. Technical review request forms will be available from the ISO.
- A 3** No later than one week after receipt of the Generator's request, the ISO shall provide the Generator with a listing of required interface equipment for Regulation, including a standard ISO direct communication and direct control system. The ISO shall send a copy of the listing to the Generator's Scheduling Coordinator.
- A 4** The Generator may propose alternatives that the Generator believes may provide an equivalent level of communication and control for consideration by the ISO. Such proposals shall be in writing and contain sufficient detail for the ISO to make a determination of suitability. The ISO may request additional information, if required, to assist in its evaluation of the proposal.
- A 5** The ISO shall respond by accepting the alternative proposal, rejecting the alternative proposal, or suggesting modifications to the alternative proposal. Such acceptance, rejection, or suggested revision must be provided not later than six weeks after the proposal is received by the ISO. The Generator and the ISO shall keep the Scheduling Coordinator informed of this process by each sending to the Scheduling Coordinator a copy of any written communication which it sends to the other.
- A 6** Upon agreement as to any alternative method of communication and control to be used by the Generator, the ISO shall provisionally approve the proposal in writing providing a copy to the Generator's Scheduling Coordinator at the same time. If agreed by the ISO, the Generator may then proceed to procure and install the equipment and make arrangements for the required communication and control.

- A 7** Design, acquisition, and installation of the ISO-approved communication and control equipment shall be under the control of the ISO. The ISO shall bear no cost responsibility or functional responsibility for such equipment, except that the ISO shall arrange for and monitor the maintenance of the communication and control system at the Generator's expense, unless otherwise agreed by the ISO and the Generator. The ISO shall be responsible for the design, acquisition and installation of any necessary modifications to the ISO EMS at its own cost.
- A 8** The ISO, in cooperation with the Generator shall perform testing of the communication and control equipment to ensure that the communication and control system performs to meet the ISO requirements.
- A 9** When the ISO is satisfied that the communication and control systems meet the ISO's requirements, the Generator shall request in writing that the ISO conduct a certification test with a suggested primary date and time and at least two alternative dates and times. The ISO shall, within two Business Days of receipt of the Generator's request, accept a proposed time if possible or suggest at least three alternatives to the Generator. If the ISO responds by suggesting alternatives, the Generator shall, within two Business Days of receipt of the ISO's response, respond in turn by accepting a proposed alternative if possible or suggesting at least three alternatives, and this procedure shall continue until agreement is reached on the date and time of the test. The Generator shall inform its Scheduling Coordinator of the agreed date and time of the test.
- A 10** Testing shall be performed by the ISO, with the cooperation of the Generator. Such tests shall include, but not be limited to, the following:
- A 10.1** confirmation of control communication path performance;
- A 10.2** confirmation of primary and secondary voice circuits for receipt of Dispatch instructions;
- A 10.3** confirmation of the Generating Unit control performance; and
- A 10.4** confirmation of the ISO EMS control to include changing the Generating Unit output over the range of Regulation proposed at different Set Points, from minimum to maximum output, and at different rates of change from the minimum to the maximum permitted by the design of the Generating Unit.
- A 11** Upon successful completion of the test, the ISO shall certify the Generating Unit as being permitted to provide Regulation as an Ancillary Service and shall provide a copy of the certificate to the Scheduling Coordinator at the same time. The ISO shall change its Generating Unit data base to reflect the permission for the Generating Unit to provide Regulation service.
- A 12** The Scheduling Coordinator may bid Regulation service from the certified Generating Unit into the Markets starting with the Day-Ahead Market for the hour ending 0100 on the second Trading Day after the ISO issues the certificate.

A 13 The certification to provide Regulation shall remain in force until:

- (a) withdrawn by the Scheduling Coordinator or the Generator by written notice to the ISO to take effect at the time notified in the notice, which must be the end of a Trading Day; or
- (b) if the Generating Unit obtained ISO certification on the basis of a prior communication and control technology, until revoked by the ISO for failure to comply with the requirement set forth in A 13.1 that the Generating Unit install an ISO-specified standard ISO direct communication and direct control system (unless exempted by the ISO).

A 13.1 Unless exempted by the ISO, if the Generating Unit obtained ISO certification on the basis of a prior communication and control technology, the ISO shall provide written notice to the Generator of the Generator's obligation to install an ISO-specified standard direct communication and direct control system along with a required date for said work to be completed as mutually agreed upon by the ISO and the Generator. Failure to meet the completion date shall be grounds for the revocation of certification, provided that the ISO must provide the Generator with at least ninety (90) days advance notice of the proposed revocation.

A 14 THE CERTIFICATION MAY BE REVOKED BY THE ISO ONLY UNDER PROVISIONS
OF THE ASRP OR THE ISO TARIFF.

PART B

CERTIFICATION FOR SPINNING RESERVE

- B 1** A Generator wishing to provide Spinning Reserve as an Ancillary Service from a Generating Unit or System Resource whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following requirements in order to be certified by the ISO to provide Spinning Reserve service:
- B 1.1** the rated capacity of the Generating Unit must be 1 MW or greater unless the Generating Unit is participating in an aggregation arrangement approved by the ISO;
- B 1.2** the minimum governor performance of the Generating Unit or System Resource shall be as follows:
- B 1.2.1** 5% drop;
- B 1.2.2** governor deadband must be plus or minus 0.036Hz; and
- B 1.2.3** the power output must change within one second for any frequency deviation outside the governor deadband.
- B 1.3** the operator of the Generating Unit or System Resource must have a means of receiving Dispatch instructions to initiate an increase in real power output (MW) within one minute of the ISO Control Center determination that Energy from Spinning Reserve capacity must be Dispatched;
- B 1.4** the Generating Unit or System Resource must be able to increase its real power output (MW) by the maximum amount of Spinning Reserve to be offered within ten minutes;
- B 1.5** ISO approved voice communications services must be in place to provide both primary and alternate voice communication between the ISO Control Center and the operator controlling the Generating Unit or System Resource; and
- B 1.6** The communication system and the Generating Unit or System Resource must pass a qualification test to demonstrate the overall ability to meet the performance requirements of the ASRP for Spinning Reserve.
- B 2** A Generator or System Unit wishing to be considered for certification for Spinning Reserve service by the ISO must make a written request to the ISO, giving details of the technical capability of the Generating Units or System Resources concerned and identifying the Scheduling Coordinator through whom the Generator or System Unit intends to offer Spinning Reserve service. The Generator or System Unit shall at the same time send a copy of its request to that Scheduling Coordinator. Technical review request forms will be available from the ISO.

- B 3** No later than one week after receipt of the request, the ISO shall provide the Generator or System Unit with a listing of acceptable communication options and interface equipment options for Spinning Reserve. The ISO shall send a copy of the listing to the Generator's or System Unit's Scheduling Coordinator.
- B 4** The Generator or System Unit may elect to implement any of the approved options defined by the ISO, and, if it wishes to proceed with its request for certification, shall give written notice to the ISO of its selected communication option, with a copy to its Scheduling Coordinator.
- B 5** When it receives the Generator's or System Unit's notice, the ISO shall notify the Generator or System Unit and the Scheduling Coordinator in writing no later than two weeks after receipt of the notice confirming receipt of the notice and issuing provisional approval of the selected options. Upon receipt of the ISO acknowledgment, the Generator or System Unit may proceed as indicated below to secure the necessary facilities and capabilities required.
- B 6** The Generator or System Unit may also propose alternatives that it believes may provide an equivalent level of control for consideration by the ISO. Such proposals shall be in writing and contain sufficient detail for the ISO to make a determination of suitability. The ISO may request additional information, if required, to assist in its evaluation of the proposal.
- B 7** The ISO shall respond by accepting the alternative proposal, rejecting the alternative proposal, or suggesting modifications to the alternative proposal. Such acceptance, rejection, or suggested revision must be provided not later than six weeks after the proposal is received by the ISO. The Generator or the System Unit and the ISO shall keep the Scheduling Coordinator informed of this process by each sending to the Scheduling Coordinator a copy of any written communication which it sends to the other.
- B 8** Upon agreement as to the method of communication and control to be used by the Generator or System Resource, the ISO shall provisionally approve the Generator's proposal or the System Resource's proposal in writing providing a copy to the Generator's or System Resource's Scheduling Coordinator at the same time. The Generator or System Resource may then proceed to procure and install the equipment and make arrangements for the required communication.
- B 9** Design, acquisition, and installation of the Generator's equipment or the System Resource's equipment shall be under the control of the respective Generator or System Resource. The ISO shall bear no cost responsibility or functional responsibility for such equipment. The ISO shall be responsible for the design, acquisition and installation of any necessary modifications to its own equipment at its own cost.
- B 10** The Generator or System Resource shall perform its own testing of its equipment to ensure that the control system performs to meet the ISO requirements.

- B 11** When it is satisfied that its plant, equipment and communication systems meet the ISO's requirements, the Generator or System Resource shall request in writing that the ISO conduct a certification test with a suggested primary date and time and at least two alternative dates and times. The ISO shall, within two Business Days of receipt of the request, accept a proposed time if possible or suggest at least three alternatives to the Generator or System Resource. If the ISO responds by suggesting alternatives, the Generator or System Resource shall, within two Business Days of receipt of the ISO's response, respond in turn by accepting a proposed alternative if possible or suggesting at least three alternatives, and this procedure shall continue until agreement is reached on the date and time of the test. The Generator or System Resource shall inform its Scheduling Coordinator of the agreed date and time of the test.
- B 12** Testing shall be performed under the direction of the ISO. Such tests shall include, but not be limited to, the following:
- B 12.1** confirmation of control communication path performance for Dispatch instruction;
- B 12.2** confirmation of primary and secondary voice circuits for receipt of Dispatch instructions;
- B 12.3** confirmation of the Generating Unit or System Resource performance to include changing the Generating Unit or System Resource output over the range of Spinning Reserve proposed from minimum to maximum output, and at different rates of change from the minimum to the maximum permitted by the design of the Generating Unit or System Resource; and
- B 12.4** testing the drop characteristic of the Generating Unit or System Resource by simulating frequency excursions outside the allowed deadband and measuring the response of the Generating Unit or System Resource.
- B 13** Upon successful completion of the test the ISO shall certify the Generating Unit or System Resource as being permitted to provide Spinning Reserve as an Ancillary Service and shall provide a copy of the certificate to the Scheduling Coordinator at the same time. The ISO shall change the Generating Unit or System Resource data base to reflect the ability of the Generating Unit to provide Spinning Reserve.
- B 14** The Scheduling Coordinator may bid Spinning Reserve from the certified Generating Unit or System Resource into the Markets starting with the Day-Ahead Market for the hour ending 0100 on the Second Trading Day after the ISO issues the certificate.
- B 15** The certification to provide Spinning Reserve shall remain in force until withdrawn by the Scheduling Coordinator or the Generator or System Resource by written notice to the ISO to take effect at the time notified in the notice, which must be the end of a Trading Day.
- B 16** The certification may be revoked by the ISO only under provisions of the ASRP or the ISO Tariff.

PART C

CERTIFICATION FOR NON-SPINNING RESERVE

- C 1** An Ancillary Service Provider wishing to provide Non-Spinning Reserve as an Ancillary Service from a Generating Unit or System Resource whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following requirements in order to be certified by the ISO to provide Non-Spinning Reserve service:
- C 1.1** the rated capacity of the Generating Unit or System Resource must be 1 MW or greater unless the Generating Unit is participating in an aggregation arrangement approved by the ISO;
- C 1.2** the Generating Unit must be able to increase output as soon as possible to the value indicated in a Dispatch instruction, reaching the indicated value within ten minutes after issue of the instruction and be capable of maintaining output for 2 hours.
- C 2** An Ancillary Service Provider wishing to provide Non-Spinning Reserve as an Ancillary Service from Curtailable Demand whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following requirements in order to be certified by the ISO to provide Non-Spinning Reserve service:
- C 2.1** the operator must be able to completely disconnect the required Load pursuant to a Dispatch instruction within ten minutes after issue of the instruction;
- C 2.2** the minimum change in the electrical consumption of the Load must be at least 1 MW; and
- C 2.3** the Load must be capable of being interrupted for at least two hours.
- C 3** An Ancillary Service Provider wishing to provide Non-Spinning Reserve as an Ancillary Service, whether pursuant to the ISO's auction or as part of a self-provision arrangement, must also meet the following requirements in order to be certified by the ISO to provide Non-Spinning Reserve service:
- C 3.1** the operator of the Generating Unit, System Resource or the Curtailable Demand must have a means of receiving a Dispatch instruction to initiate an increase in real power output or a reduction in Demand (MW) within one minute of the ISO Control Center's determination that Non-Spinning Reserve capacity must be Dispatched; and
- C 3.2** the communication system and the Generating Unit, System Resource or Load must pass a qualification test to demonstrate the overall ability to meet the performance requirements of the ASRP for Non-Spinning Reserve.
- C 4** An Ancillary Service Provider wishing to be considered for certification for Non-Spinning Reserve service must make a written request to the ISO, giving details of the technical capability of the Generating Unit, System Resource or Load concerned and identifying the Scheduling Coordinator through whom the Ancillary Service Provider intends to offer Non-Spinning Reserve. The Ancillary Service Provider shall at the same time send a

copy of the request to that Scheduling Coordinator. Technical Review request forms will be available from the ISO.

- C 5** No later than one week after receipt of the Ancillary Service Provider's request, the ISO shall provide the Ancillary Service Provider with a listing of acceptable communication options and interface equipment options for Non-Spinning Reserve. The ISO shall send a copy of the listing to the Ancillary Service Provider's Scheduling Coordinator.
- C 6** The Ancillary Service Provider may elect to implement any of the certification, the Ancillary Service Provider shall give written notice to the ISO of its selected communication option and interface equipment option, with a copy to its Scheduling Coordinator.
- C 7** When it receives the Ancillary Service Provider's notice, the ISO shall notify the Ancillary Service Provider and the Scheduling Coordinator in writing no later than two weeks after receipt of the notice confirming receipt of the notice and issuing provisional approval of the selected options. Upon receipt of the ISO acknowledgment the Ancillary Service Provider may proceed as indicated below to secure the necessary facilities and capabilities required.
- C 8** The Ancillary Service Provider may also propose alternatives that it believes may provide an equivalent level of control for consideration by the ISO. Such proposals shall be in writing and contain sufficient detail for the ISO to make a determination of suitability. The ISO may request additional information, if required, to assist in its evaluation of the proposal.
- C 9** The ISO shall respond by accepting the alternative proposal, rejecting the alternative proposal, or suggesting modifications to the alternative proposal. Such acceptance, rejection, or suggested revision must be provided not later than six weeks after the proposal is received by the ISO. The Ancillary Service Provider and the ISO shall keep the Scheduling Coordinator informed of this process by each sending to the Scheduling Coordinator a copy of any written communication which it sends to the other.
- C 10** Upon agreement as to the method of communication and control to be used by the Ancillary Service Provider, the ISO shall provisionally approve the proposal in writing providing a copy to the Ancillary Service Provider's Scheduling Coordinator at the same time. The Ancillary Service Provider may then proceed to procure and install the equipment and make arrangements for the required communication.
- C 11** Design, acquisition, and installation of the Ancillary Service Provider's equipment shall be under the control of the Ancillary Service Provider. The ISO shall bear no cost responsibility or functional responsibility for such equipment. The ISO shall be

responsible for the design, acquisition and installation of any necessary modifications to the ISO's equipment at its own cost.

- C 12** The Ancillary Service Provider shall perform its own testing of its equipment to ensure that the control system performs to meet the ISO requirements.
- C 13** When it is satisfied that its plant, equipment and communication systems meet the ISO's requirements, the Ancillary Service Provider shall request in writing that the ISO conduct a certification test with a suggested primary date and time and at least two alternative dates and times. The ISO shall, within two Business Days of receipt of the Ancillary Service Provider's request, accept a proposed time if possible or suggest at least three alternatives. If the ISO responds by suggesting alternatives, the Ancillary Service Provider shall, within two Business Days of receipt of the ISO's response, respond in turn by accepting a proposed alternative if possible or suggesting at least three alternatives, and this procedure shall continue until agreement is reached on the date and time of the test. The Ancillary Service Provider shall inform its Scheduling Coordinator of the agreed date and time of the test.
- C 14** Testing shall be performed under the direction of the ISO. Such tests shall include, but not be limited to, the following:
- C 14.1** confirmation of control communication path performance;
- C 14.2** confirmation of primary and secondary voice circuits for receipt of Dispatch instructions;
- C 14.3** confirmation of the Generating Unit, System Resource or Load control performance; and
- C 14.4** confirmation of the range of Generating Unit or System Resource control to include changing the output over the range of Non-Spinning Reserve proposed.
- C 15** Upon successful completion of the test, the ISO shall certify the Generating Unit, System Resource or Load as being permitted to provide Non-Spinning Reserve as an Ancillary Service and shall provide a copy of the certificate to the Scheduling Coordinator at the same time. The ISO shall change its data base to reflect the permission for the Generating Unit or Load to provide Non-Spinning Reserve service.
- C 16** The Scheduling Coordinator may bid Non-Spinning Reserve service from the certified Generating Unit or Load into the Markets starting with the Day-Ahead Market for the hour ending 0100 on the second Trading Day after the ISO issues the certificate.
- C 17** The certification to provide Non-Spinning Reserve shall remain in force until withdrawn by the Scheduling Coordinator or the Ancillary Service Provider by written notice to the ISO to take effect at the time notified in the notice, which must be the end of a Trading Day.

- C 18** The certification may be revoked by the ISO only under provisions of the ASRP or the ISO Tariff.

PART D

CERTIFICATION FOR REPLACEMENT RESERVE

- D 1** An Ancillary Service Provider wishing to provide Replacement Reserve as an Ancillary Service from a Generating Unit or System Resource whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following requirements in order to be certified by the ISO to provide Replacement Reserve service:
- D 1.1** the rated capacity of the Generating Unit or System Resource must be 1 MW or greater unless the Generating Unit is participating in an aggregation arrangement approved by the ISO;
- D 1.2** the operator of the Generating Unit must be able to increase output as quickly as possible to a value indicated in a Dispatch instruction, reaching the indicated value in sixty minutes or less after issue of the instruction.
- D 2** An Ancillary Service Provider wishing to provide Replacement Reserve as an Ancillary Service from Curtailable Demand whether pursuant to the ISO's auction or as part of a self-provision arrangement must meet the following requirements in order to be certified by the ISO to provide Replacement Reserve service:
- D 2.1** the operator must be able to completely disconnect the required Load pursuant to a Dispatch instruction within sixty minutes after issue of the instruction;
- D 2.2** the minimum change in the electrical consumption of the Load must be at least 1 MW; and
- D 2.3** the Load must be capable of being interrupted for at least two hours.
- D 3** An Ancillary Service Provider wishing to provide Replacement Reserve as an Ancillary Service, whether pursuant to the ISO's auction or as part of a self-provision arrangement, must also meet the following requirements in order to be certified by the ISO to provide Replacement Reserve service:
- D 3.1** the operator of the Generating Unit, System Resource or the Curtailable Demand must have a means of receiving a Dispatch instruction to initiate an increase in real power output or a reduction in Demand (MW) within one minute of the ISO Control Center's determination that Replacement Reserve capacity must be Dispatched; and
- D 3.2** the communication system and the Generating Unit or Load must pass a qualification test to demonstrate the overall ability to meet the performance requirements of the ASRP for Replacement Reserve.
- D 4** An Ancillary Service Provider wishing to be considered for certification for Replacement Reserve service must make a written request to the ISO, giving details of the technical capability of the Generating Unit, System Resource or the Load concerned and identifying the Scheduling Coordinator through whom the Ancillary Service Provider intends to offer Replacement Reserve. The Ancillary Service Provider shall at the same time send a copy of its request to that Scheduling Coordinator. Technical Review request forms will be available from the ISO.
- D 5** No later than one week after receipt of the Ancillary Service Provider's request, the ISO shall provide the Ancillary Service Provider with a listing of acceptable communication options and interface equipment options for Replacement Reserve. The ISO shall send a copy of the listing to the Ancillary Service Provider's Scheduling Coordinator.
- D 6** The Ancillary Service Provider may elect to implement any of the options defined by the ISO, and, if it wishes to proceed with its request for certification, the Ancillary Service Provider shall give

written notice to the ISO of its selected communication option and interface equipment option, with a copy to its Scheduling Coordinator.

- D 7** When it receives the Ancillary Service Provider's notice, the ISO shall notify the Ancillary Service Provider and the Scheduling Coordinator in writing no later than two weeks after receipt of the notice confirming receipt of the notice and issuing provisional approval of the selected options. Upon receipt of the ISO acknowledgment the Ancillary Service Provider may proceed as indicated below to secure the necessary facilities and capabilities required.
- D 8** The Ancillary Service Provider may also propose alternatives that it believes may provide an equivalent level of control for consideration by the ISO. Such proposals shall be in writing and contain sufficient detail for the ISO to make a determination of suitability. The ISO may request additional information, if required, to assist in its evaluation of the proposal.
- D 9** The ISO shall respond by accepting the alternative proposal, rejecting the alternative proposal, or suggesting modifications to the alternative proposal. Such acceptance, rejection, or suggested revision shall be provided not later than six weeks after the proposal is received by the ISO. The Ancillary Service Provider and the ISO shall keep the Scheduling Coordinator informed of this process by each sending to the Scheduling Coordinator a copy of any written communication which it sends to the other.
- D 10** Upon agreement as to the method of communication and control to be used by the Ancillary Service Provider, the ISO shall provisionally approve the proposal in writing providing a copy to the Ancillary Service Provider's Scheduling Coordinator at the same time. The Ancillary Service Provider may then proceed to procure and install the equipment and make arrangements for the required communication.
- D 11** Design, acquisition, and installation of the Ancillary Service Provider's equipment shall be under the control of the Ancillary Service Provider. The ISO shall bear no cost responsibility or functional responsibility for such equipment. The ISO shall be responsible for the design, acquisition and installation of any necessary modifications to the ISO's equipment at its own cost.
- D 12** The Ancillary Service Provider shall perform its own testing of its equipment to ensure that the control system performs to meet the ISO requirements.
- D 13** When it is satisfied that its plant, equipment and communication systems meet the ISO's requirements, the Ancillary Service Provider shall request in writing that the ISO conduct a certification test with a suggested primary date and time and at least two alternative dates and times. The ISO shall, within two Business Days of receipt of the Ancillary Service Provider's request, accept a proposed time if possible or suggest at least three alternatives. If the ISO responds by suggesting alternatives, the Ancillary Service Provider shall, within two Business Days of receipt of the ISO's response, respond in turn by accepting a proposed alternative if possible or suggesting at least three alternatives, and this procedure shall continue until agreement is reached on the date and time of the test. The Ancillary Service Provider shall inform its Scheduling Coordinator of the agreed date and time of the test.
- D 14** Testing shall be performed under the direction of the ISO. Such tests shall include, but not be limited to, the following:
- D 14.1** confirmation of control communication path performance;
- D 14.2** confirmation of primary and secondary voice circuits for receipt of Dispatch instructions;
- D 14.3** confirmation of the Generating Unit, System Resource or Load control performance; and

- D 14.4** confirmation of the range of Generating Unit or System Resource control to include changing the Generating Unit output over the range of Replacement Reserve proposed.
- D 15** Upon successful completion of the test the ISO shall certify the Generating Unit, System Resource or Load as being permitted to provide Replacement Reserve as an Ancillary Service and shall provide a copy of the certificate to the Scheduling Coordinator at the same time. The ISO shall change its data base to reflect the permission for the Generating Unit or Load to provide Replacement Reserve service.
- D 16** The Scheduling Coordinator may bid Replacement Reserve service from the certified Generating Unit or Load into the Markets starting with the Day-Ahead Market for the hour ending 0100 on the second Trading Day after the ISO issues the certificate.
- D 17** The certification to provide Replacement Reserve shall remain in force until withdrawn by the Scheduling Coordinator or the Ancillary Service Provider by written notice to the ISO to take effect at the time notified in the notice, which must be the end of a Trading Day.
- D 18** **THE CERTIFICATION MAY BE REVOKED BY THE ISO ONLY UNDER PROVISIONS OF THE ASRP OR THE ISO TARIFF.**

PART E

CERTIFICATION FOR VOLTAGE SUPPORT

- E 1** A Generator wishing to provide Voltage Support as an Ancillary Service from a Generating Unit must meet the following requirements in order to be certified by the ISO to provide Voltage Support service:
- E 1.1** the rated capacity of the Generating Unit must be 1 MW or greater unless the Generating Unit is participating in an aggregation arrangement approved by the ISO;
- E 1.2** the Generating Unit must be able to produce VARs at lagging power factors less than 0.90 and absorb VARs at leading power factors more than 0.95 within the safe operating parameters for the Generating Unit;
- E 1.3** the Generating Unit must be able to produce or absorb VARs outside the 0.90 lag to 0.95 lead bandwidth over a range of real power outputs which the Generator expects to produce when offering Voltage Support;
- E 1.4** the Generating Unit must be able to produce or absorb VARs at the boundary of the Generating Unit's capability curve by reducing real power output to either absorb or produce additional VARs within the safe operating parameters for the Generating Unit; and
- E 1.5** metering and SCADA equipment must be in place to provide both real and reactive power data from the Generating Unit providing Voltage Support to the ISO Control Center.
- E 2** A Generator wishing to be considered for certification for Voltage Support service by the ISO must make a written request to the ISO, giving details of the technical capability of the Generating Unit concerned and identifying the Scheduling Coordinator through whom the Generator intends to offer Voltage Support service. The Generator shall at the same time send a copy of its request to that Scheduling Coordinator. The details of the Generating Unit's technical capability must include the Generating Unit name plate data, performance limits, and capability curve. The Generator must also define the operating limitations in both real and reactive power (lead and lag) to be observed when Voltage Support is being provided to the ISO for both normal and reduced real power output conditions. Technical Review request forms will be available from the ISO.
- E 3** No later than one week after receipt of the Generator's request, the ISO shall provide the Generator with a listing of acceptable communication options and interface equipment options for Voltage Support. The ISO shall send a copy of the listing to the Generator's Scheduling Coordinator.
- E 4** The Generator may elect to implement any of the approved options defined by the ISO, and, if it wishes to proceed with its request for certification, the Generator shall give written notice to the ISO of its selected communication option and interface equipment option, with a copy to its Scheduling Coordinator.

- E 5** When it receives the Generator's notice the ISO shall notify the Generator and the Scheduling Coordinator in writing no later than two weeks after receipt of the notice confirming receipt of the notice and issuing provisional approval of the selected options. Upon receipt of the ISO acknowledgment the Generator may proceed as indicated below to secure the necessary facilities and capabilities required.
- E 6** The Generator may also propose alternatives that the Generator believes may provide an equivalent level of control for consideration by the ISO. Such proposals shall be in writing no later than two weeks after receipt of the notice and contain sufficient detail for the ISO to make a determination of suitability. The ISO may request additional information, if required, to assist in its evaluation of the proposal.
- E 7** The ISO shall respond by accepting the alternative proposal, rejecting the alternative proposal, or suggesting modifications to the alternative proposal. Such acceptance, rejection, or suggested revision shall be provided not later than six weeks after the proposal is received by the ISO. The Generator and the ISO shall keep the Scheduling Coordinator informed of this process by each sending to the Scheduling Coordinator a copy of any written communication which it sends to the other.
- E 8** Upon agreement as to the method of communication and control to be used by the Generator, the ISO shall provisionally approve the proposal in writing providing a copy to the Generator's Scheduling Coordinator at the same time. The Generator may then proceed to procure and install the equipment and make arrangements for the required communication.
- E 9** Design, acquisition, and installation of the Generator's equipment are under the control of the Generator. The ISO shall bear no cost responsibility or functional responsibility for such equipment.
- E 10** The ISO shall be responsible for the design, acquisition and installation of any necessary modifications to the ISO's equipment at its own cost.
- E 11** The Generator shall perform its own testing of its equipment to ensure that the control system performs to meet the ISO requirements.
- E 12** When it is satisfied that its plant, equipment and communication systems meet the ISO's requirements, the Generator shall request in writing that the ISO conduct a certification test with a suggested primary date and time and at least two alternative dates and times. The ISO shall, within two Business Days of receipt of the Generator's request, accept a proposed time if possible or suggest at least three alternatives to the Generator. If the ISO responds by suggesting alternatives, the Generator shall, within two Business Days of receipt of the ISO's response, respond in turn by accepting a proposed alternative if possible or suggesting at least three alternatives, and this procedure shall continue until agreement is reached on the date and time of the test. The Generator shall inform its Scheduling Coordinator of the agreed date and time of the test.
- E 13** Testing shall be performed under the direction of the ISO. Such tests shall include, but not be limited to, the following:
- E 13.1** confirmation of control communication path performance;

- E 13.2** confirmation of primary and secondary voice circuits for receipt of Dispatch instructions;
- E 13.3** confirmation of the Generating Unit automatic voltage regulator performance; and
- E 13.4** confirmation of the range of Voltage Support service over a range of Generating Unit real power outputs to verify the ability to both produce and absorb reactive power at different operating levels including minimum and maximum real power output.
- E 14** Upon successful completion of the test, the ISO shall certify the Generating Unit as being permitted to provide Voltage Support as an Ancillary Service and shall provide a copy of the certificate to the Scheduling Coordinator at the same time. The ISO shall change the Generating Unit data base to reflect the permission for the Generating Unit to provide Voltage Support.
- E 15** The Scheduling Coordinator may bid Supplemental Energy for Voltage Support from the certified Generating Unit into the market starting with the market for the hour ending 0100 on the first Trading Day after the ISO issues the certificate.
- E 16** The certification to provide Voltage Support shall remain in force until withdrawn by the Scheduling Coordinator or the Generator by written notice to the ISO to take effect at the time notified in the notice, which must be the end of a Trading Day.
- E 17** The certification may be revoked by the ISO only under provisions of the ASRP or the ISO Tariff.

PART F

CERTIFICATION FOR BLACK START

- F 1** A Generator wishing to provide Black Start capacity from a Generating Unit as an Ancillary Service must meet the requirements stated in Appendix D of the ISO Tariff in order to be certified by the ISO to provide Black Start capacity. In addition, the Generating Unit must have a rated capacity 1 MW or greater unless the Generating Unit is participating in an aggregation arrangement approved by the ISO.
- F 2** A Generator wishing to be considered for certification for Black Start service by the ISO must make a written request to the ISO. Such request must clearly identify the facilities related to the Generating Unit from which the Generator wishes to provide Black Start and shall identify the Scheduling Coordinator through whom the Generator wishes to offer Black Start service. The Generator shall send a copy of its request to its Scheduling Coordinator at the same time as it sends it to the ISO. The Generator's written request must include at least the following:
- F 2.1** identification of the Generating Unit including Location Code;
- F 2.2** a single-line electrical diagram of the Generating Unit connections including auxiliary power busses and the connection to the station switchyard;
- F 2.3** a description of the fuel supply used for Black Start including on-site storage and resupply requirements;
- F 2.4** a single-line electrical diagram showing the transmission connection from the Generating Unit station switchyard to a connection point on the ISO Controlled Grid;
- F 2.5** a description of the Generating Unit capability to provide both real and reactive power, any start-up and shut-down requirements, any staffing limitations; and
- F 2.6** a description of the primary, alternate and emergency back-up communications systems currently available to the Generator for communications to the ISO Control Center.
- F 3** Upon receipt of the Generator's written request the ISO shall review the information provided and respond in writing within two weeks of receipt of the request, providing a copy of its response to the Generator's Scheduling Coordinator. The ISO response may be any of the following:
- F 3.1** acceptance of the proposal as presented;
- F 3.2** rejection of the proposal as presented with a rationale for such rejection; or
- F 3.3** a request for additional information needed by the ISO to properly evaluate the request.
- F 4** A Generator receiving a rejection may submit a written request for reconsideration by the ISO within 60 days of the date of the rejection notice. A request for reconsideration must address the rationale provided by the ISO. The ISO shall respond to a request for reconsideration within 60 days of the date of that request.
- F 5** A Generator receiving a request for additional information shall provide such information within 60 days of such request providing a copy at the same time to its Scheduling Coordinator. The ISO shall review the information and respond within 120 days of the

date of the ISO's request for additional information providing a copy at the same time to the Generator's Scheduling Coordinator.

- F 6** Upon acceptance by the ISO of the Generator's request and agreement as to the method of communication and control to be used by the Generator, the ISO shall provisionally approve the proposal in writing providing a copy at the same time to the Generator's Scheduling Coordinator. The Generator may then proceed to procure and install the equipment and make arrangements for the required communication.
- F 7** Design, acquisition, and installation of the Generator's equipment shall be under the control of the Generator. The ISO shall bear no cost responsibility or functional responsibility for such equipment. The ISO shall be responsible for the design, acquisition and installation of any necessary modifications to its own equipment at its own cost.
- F 8** The Generator shall perform its own testing of its equipment to ensure that the Black Start system performs to meet the ISO requirements.
- F 9** When it is satisfied that its plant, equipment and communication systems meet the ISO's requirements, the Generator shall request in writing that the ISO conduct a certification test with a suggested primary date and time and at least two alternative dates and times. The ISO shall, within two Business Days of receipt of the Generator's request, accept a proposed time if possible or suggest at least three alternatives to the Generator. If the ISO responds by suggesting alternatives, the Generator shall, within two Business Days of receipt of the ISO's response, respond in turn by accepting a proposed alternative if possible or suggesting at least three alternatives, and this procedure shall continue until agreement is reached on the date and time of the test. The Generator shall inform its Scheduling Coordinator of the agreed date and time of the test.
- F 10** Testing shall be performed under the direction of the ISO. Such tests shall include, but not be limited to, the following:
- F 10.1** confirmation of control communication path performance;
- F 10.2** confirmation of primary, secondary, and emergency voice circuits for receipt of Dispatch instructions;
- F 10.3** confirmation of the Generating Unit performance; and
- F 10.4** simulation of a Black Start event.
- F 11** Upon successful completion of the test, the ISO shall certify the Generating Unit as being permitted to provide Black Start capacity as an Ancillary Service and shall provide a copy of the certificate to the Scheduling Coordinator at the same time. The ISO shall

change its Generating Unit data base to reflect the permission for the Generating Unit to provide Black Start service.

- F 12** The certification to provide Black Start shall remain in force until withdrawn by the Scheduling Coordinator or the Generator by written notice to the ISO to take effect at the time noticed in the notice, which must be the end of a Trading Day.
- F 13** The certification may be revoked by the ISO only under provisions of the ASRP or the ISO Tariff.

ISO TARIFF APPENDIX L

Methodology to Assess Available Transfer Capability

METHODOLOGY TO ASSESS AVAILABLE TRANSFER CAPABILITY

L.1 Description of Terms

The following descriptions augment existing definitions found in Appendix A "Master Definitions Supplement."

L.1.1 Available Transfer Capability (ATC) is a measure of the transfer capability in the physical transmission network resulting from system conditions and that remains available for further commercial activity over and above already committed uses.

ATC is defined as the Total Transfer Capability (TTC) less applicable operating Constraints due to system conditions and Outages (i.e., OTC), less the Transmission Reliability Margin (TRM), less the total of Existing Transmission Commitments (ETC), less the Capacity Benefit Margin (CBM).

L.1.2 Total Transfer Capability (TTC) is defined as the amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission system by way of all transmission lines (or paths) between those areas. In collaboration with owners of rated paths and the WECC Operating Transfer Capability Policy Committee (OTCPC), the ISO utilizes Rated Path Methodology to establish the TTC of ISO branch groups.

L.1.3 Operating Transfer Capability (OTC) is the TTC reduced by any operational Constraints caused by seasonal derates or Outages. ISO Regional Transmission Engineers determine OTC through studies using computer modeling.

L.1.4 Existing Transmission Commitments (ETC) include Existing Contracts, and as appropriate, Firm Transmission Rights, and Transmission Ownership Rights.

L.1.5 Transmission Reliability Margin (TRM) is that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. TRM reserves sufficient transmission capacity from the Day-Ahead (DA) Market to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. This DA implementation avoids real time schedule curtailments that would otherwise be necessary due to:

- Load forecast error
- Anticipated uncertainty in transmission system topology
- Unscheduled Flow
- Simultaneous path interactions
- Variations in generation dispatch
- Operating reserve actions

The level of TRM for each branch group will be determined by ISO Regional Transmission Engineers (RTE).

L.1.6 Capacity Benefit Margin (CBM) is that amount of transmission transfer capability reserved by Load Serving Entities (LSEs) to ensure access to generation from interconnected systems to meet generation reliability requirements. In the DA Market, CBM may be used to provide reliable delivery of Energy to ISO Control Area Loads and to meet ISO responsibility for resource reliability requirements in real time. The purpose of this DA implementation is to avoid real time schedule curtailments and firm load interruptions that would otherwise be necessary. CBM may be used to reestablish Operating Reserves. CBM is not available for non-firm transmission in the ISO Control Area. CBM may be used only after:

- all non-firm sales have been terminated,
- Direct-control Load management has been implemented,
- customer interruptible demands have been interrupted,
- if the LSE calling for its use is experiencing a Generation deficiency and its transmission service provider is also experiencing transmission constraints relative to imports of Energy on its transmission system.

The level of CBM for each branch group is determined by the amount of estimated capacity needed to serve firm Load and provide Operating Reserves based on historical, scheduled, and/or forecast data using the following equation to set the maximum CBM:

$$\text{CBM} = (\text{Demand} + \text{Reserves}) - \text{Resources}$$

Where:

- Demand = forecasted area demand
- Reserves = reserve requirements
- Resources = internal area resources plus resources available on other branch groups

L.2 ATC Algorithm

$$\text{ATC} = \text{OTC} - (\text{TRM} + \text{ETC} + \text{CBM})$$

or

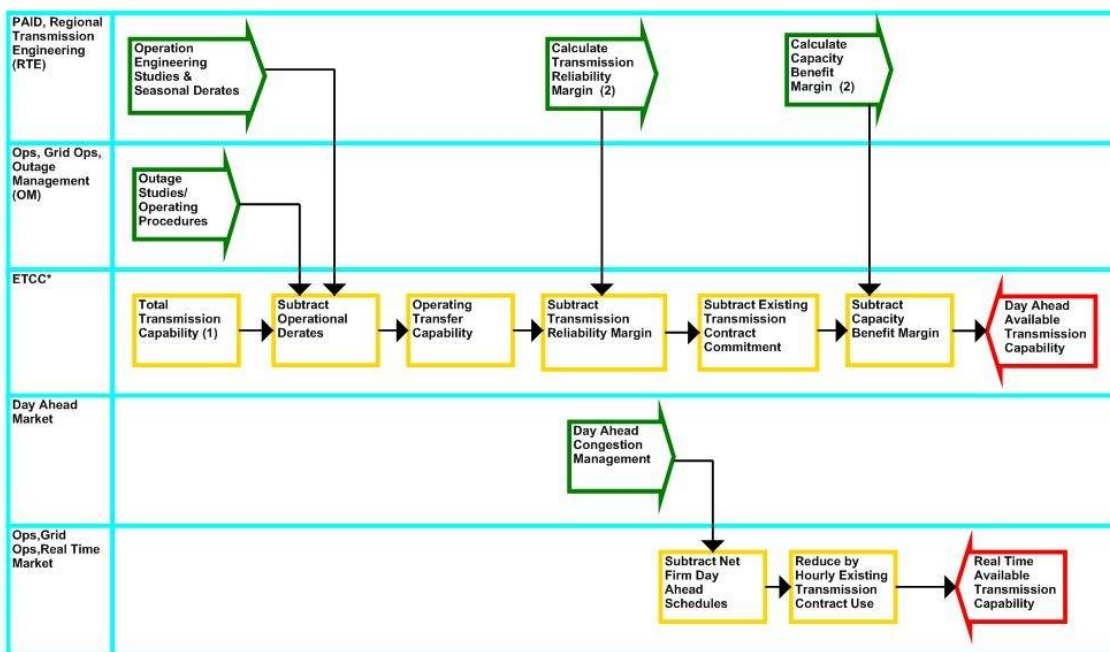
$$\text{ATC} = (\text{TTC} - \text{Operating Constraints}) - (\text{TRM} + \text{ETC} + \text{CBM})$$

Where:

- OTC = TTC – Operating Constraints
- TTC = Total Transfer Capability
- OTC = Operating Transfer Capability
- TRM = Transmission Reliability Margin
- ETC = Existing Transmission Commitments
- CBM = Capacity Benefit Margin

L.3 ATC Process Flowchart

Available Transmission Capability



* ETCC - Existing Transmission Contract Calculator
 (1) WECC rated path methodology
 (2) S- 322

L.4 TTC – OTC Determination

All transfer capabilities are developed to ensure that power flows are within their respective operating limits, both pre-Contingency and post-Contingency. Operating limits are developed based on thermal, voltage and stability concerns according to industry reliability criteria (WECC/NERC) for transmission paths. The process for developing TTC or OTC is the same with the exception of inclusion or exclusion of operating Constraints based on system conditions being studied. Accordingly, further description of the process to determine either OTC or TTC will refer only to TTC.

L.4.1 Transfer capabilities for studied configurations may be used as a maximum transfer capability for similar conditions without conducting additional studies. Increased transfer capability for similar conditions must be supported by conducting appropriate studies.

L.4.1.2 At ISO, studies for all major inter-area paths (mostly 500 kV) OTC are governed by the California Operating Studies Subcommittee (OSS) as one of four sub-regional Study Groups of the WECC OTCPC (i.e., for California Sub-region), which provides detailed criteria and methodology. For transmission system elements below 500 kV the methodology for calculating these flow limits is detailed in C.4.3 and is applicable to the operating horizon.

L.4.2 Transfer capability may be limited by the physical and electrical characteristics of the systems including any one or more of the following:

- **Thermal Limits** – Thermal limits establish the maximum amount of electric current that a transmission line or electrical facility can conduct over a specified time-period as established by the Transmission Owner.
- **Voltage Limits** – System voltages and changes in voltages must be maintained within the range of acceptable minimum and maximum limits to avoid a widespread collapse of system voltage.
- **Stability Limits** – The transmission network must be capable of surviving disturbances through the transient and dynamic time-periods (from milliseconds to several minutes, respectively) following the disturbance so as to avoid generator instability or uncontrolled, widespread interruption of electric supply to customers.

L.4.3 Determination of transfer capability is based on computer simulations of the operation of the interconnected transmission network under a specific set of assumed operating conditions. Each simulation represents a single “snapshot” of the operation of the interconnected network based on the projections of many factors. As such, they are viewed as reasonable indicators of network performance and may ultimately be used to determine Available Transfer Capability. The study is meant to capture the worst operating scenario based on the RTE experience and good engineering judgment.

L.4.3.1 System Limits – The transfer capability of the transmission network may be limited by the physical and electrical characteristics of the systems including thermal, voltage, and stability consideration. Once the critical Contingencies are identified, their impact on the network must be evaluated to determine the most restrictive of those limitations. Therefore, the TTC_1 becomes:

$$TTC_1 = \text{lesser of } \{\text{Thermal Limit, Voltage Limit, Stability Limit}\} \text{ following } N-1_{\text{worst}}$$

L.4.3.2 Parallel path flows will be considered in determining transfer capability and must be sufficient in scope to ensure that limits throughout the interconnected network are addressed. In some cases, the parallel path flows may result in transmission limitations in systems other than the transacting systems, which can limit the TTC between two transacting areas. This will be labeled TTC_2 . Combined with C.4.3.1 above TTC becomes:

$$TTC = \text{lesser of } \{TTC_1 \text{ or } TTC_2\}$$

L.5 Developing a Power Flow Base-Case

L.5.1 Base-cases will be selected used to model reality to the greatest extent possible including attributes like area Generation, area load, intertie flows, etc. At other times (e.g., studying longer range horizons), it is prudent to stress a base-case by making one or more attributes (load, Generation, line flows, path flows, etc.) of that base-case more extreme than would otherwise be expected.

L.5.2. Power Flow Base-Cases Separated By Geographic Region

The standard RTE base-cases are split into five geographical regions in the ISO Controlled Grid including the Bay Area, Fresno Area, North Area, SDG&E Area, and SCE Area.

L.5.3. Power Flow Base-Cases Selection Methodology

The RTE determines the studied geographical area of the procedure. This determines the study base-cases from the Bay Area, Fresno Area, North Area, SCE Area, or SDG&E Area.

The transfer capability studies may require studying a series of base-cases including both peak and off-peak operation conditions.

L.5.4 Update a Power Flow Base-Case

After the RTE has obtained one or more base-case studies, the base-case will be updated to represent the current grid conditions during the applicable season. The following will be considered to update the base-cases:

- Recent Transmission Network Changes and Updates
- Overlapping Scheduled and Forced Outages
- Area Load Level
- Major Path Flows
- Generation level
- Voltage Levels
- Operating Requirements

L.5.4.1 Outage Consideration

Unless detailed otherwise, the RTE considers modeling outages of:

- Transmission lines, 500 kV
- Transformers, 500/230 kV
- Large Generating Units
- Generating Units within the studied area
- Transmission elements within the studied area

At the judgment of the RTE, only the necessary outages will be modeled to avoid an unnecessarily burdensome and large number of base-cases.

L.5.4.2 Area Load Level

Base-case demand levels should be appropriate to the current studied system conditions and customer demand levels under study and may be representative of peak, off-peak or shoulder, or light demand conditions. The RTE estimates the area load levels to be utilized in the peak, partial-peak and/or off-peak base-cases. The RTE will utilize the current ISO load forecasting program (e.g., ALFs), ProcessBook (PI) or other competent method to estimate load level for the studied area. Once the RTE has determined the correct load levels to be utilized, the RTE may scale the scale the base-case loads to the area studied, as appropriate.

L.5.4.3 Modify Path Flows

The scheduled electric power transfers considered representative of the base system conditions under analysis and agreed upon by the parties involved will be used for modeling. As needed, the RTE may estimate select path flows depending on the studied area. In the event that it is not possible to estimate path flows, the RTE will make safe assumptions about the path flows. A safe assumption is more extreme or less extreme (as conservative to the situation) than would otherwise be expected.

If path flow forecasting is necessary, if possible the RTE will trend path flows on previous similar days.

L.5.4.4 Generation Level

Utility and non-utility Generating Units will be updated to keep the swing Generating Unit at a reasonable level. The actual unit-by-unit Dispatch in the studied area is more vital than in the un-studied areas. The RTE will examine past performance of select Generating Units to estimate the Generation levels, focusing on the Generating Units within the studied area. In the judgment of the RTE, large Generating Units outside the studied area will also be considered.

L.5.4.5 Voltage Levels

Studies will maintain appropriate voltage levels, based on operation procedures for critical buses for the studied base-cases. The RTE will verify that bus voltage for critical busses is within tolerance. If a bus voltage is outside the tolerance band, the RTE will model the use of voltage control devices (e.g., synchronous condensers, shunt capacitors, shunt reactors, series capacitors, generators).

L.6 Contingency Analysis

The RTE will perform Contingency analysis studies in an effort to determine the limiting conditions, especially for scheduled Outages, including pre- and post-Contingency power flow analysis modeling pre- and post-Contingency conditions and measuring the respective line flows, and bus voltages.

Other studies like reactive margin and stability may be performed as deemed appropriate.

L.6.1 Operating Criteria and Study Standards

Using standards derived from NERC and WECC Reliability Standards and historical operating experience, the RTE will perform Contingency analysis with the following operating criteria:

Pre-Contingency

- All pre-Contingency line flows shall be at or below their normal ratings.
- All pre-Contingency bus voltages shall be within a pre-determined operating range.

Post-Contingency

- All post-Contingency line flows shall be at or below their emergency ratings.
- All post-Contingency bus voltages shall be within a pre-determined operating range.

The RTE models the following Contingencies:

- Generating Unit Outages (including combined cycle Generating Unit Outages which are considered single Contingencies).
- Line Outages
- Line Outages combined with one Generating Unit Outage
- Transformer Outages
- Synchronous condenser Outages
- Shunt capacitor or capacitor bank Outages
- Series capacitor Outages
- Static VAR compensator Outages
- Bus Outages – bus Outages can be considered for the following ongoing Outage conditions.
 - For a circuit breaker bypass-and-clear Outage, bus Contingencies shall be taken on both bus segments that the bypassed circuit breaker connects to.
 - For a bus segment Outage, the remaining parallel bus segment shall be considered as a single Contingency.
 - Credible overlapping Contingencies – Overlapping Contingencies typically include transmission lines connected to a common tower or close proximity in the same right-of-way.

L.6.2 Manual Contingency Analysis

If manual Contingency analysis is used, the RTE will perform pre-Contingency steady-state power flow analysis and determines if pre-Contingency operating criteria is violated. If pre-Contingency operating criteria cannot be preserved, the RTE records the lines and buses that are not adhering to the criteria. If manual post-Contingency analysis is used the RTE obtains one or more Contingencies in each of the base cases. For each Contingency resulting in a violation or potential violation in the operating criteria above, the RTE records the critical post-Contingency facility loadings and bus voltages.

L.6.3 Contingency Analysis Utilizing a Contingency Processor

For a large area, the RTE may utilize a Contingency processor.

L.6.4 Determination of Crucial Limitations

After performing Contingency analysis studies, the RTE analyzes the recorded information to determine limitations. The limitations are conditions where the pre-Contingency and/or post-Contingency operating criteria cannot be conserved and may include a manageable overload on the facilities, low post-Contingency bus voltage, etc. If no crucial limitations are determined, the RTE determines if additional studies are necessary.

L.7 Traditional Planning Methodology to Protect Against Violating Operating Limits

After performing Contingency analysis studies, the RTE next develops the transfer capability and develops procedures, nomograms, RMR Generation requirements, or other constraints to ensure that transfer capabilities respect operating limits.

L.8 Limits for Contingency Limitations

Transfer limits are developed when the post-Contingency loading on a transmission element may breach the element's emergency rating. The type of limit utilized is dependent on the application and includes one of the following limits:

- Simple Flow Limit - best utilized when the derived limit is repeatable or where parallel transmission elements feed radial load.
- RAS or SPS – existing remedial action schemes (RAS) or special protection systems (SPS) may impact the derivation of simple flow limits. When developing the limit, the RTE determines if the RAS or SPS will be in-service during the Outage and factors the interrelationship between the RAS or SPS and the derived flow limit. RTE will update the transfer limits in recognition of the changing status and/or availability of the RAS or SPS.

ISO TARIFF APPENDIX M
Transmission Rights/Curtailment Instructions Template

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
 FERC ELECTRIC TARIFF
 THIRD REPLACEMENT VOLUME NO. II

Original Sheet No. 787

TRANSMISSION RIGHTS/CURTAILMENT INSTRUCTIONS TEMPLATE

(a) Contract Ref #	(b) Ind Imp	(c) Contact Person
[a single number]	[yes/no]	[phone number] [name(s)]

Submitted By PTO:
 Date Received By ISO:
 Date Accepted By ISO:

(d) Contract Name(s)/Number(s)	(e) Path Name(s) and Location(s)			(f) Party	(g) SC ID	(h) ER/NCR	(i)(j) Types and Amounts of Transmission Service			(k) DA	(l) HA	(m) RT	(n) Service Period	
	Path Name(s)	POR Zone	POD Zone				Firm /1/	CF /1/	N-F				(hour-ending)	(minutes)
[name/number 1]		[zone name]	[zone name]	[party 1] [party 2] [party n]	[sc id 1] [sc id 2] [sc id n]	[er] [ncr] [er]	[MW] ["] ["]	[MW] ["] ["]	[MW] ["] ["]	[1400]	[30] [n/a] [20]	[yes] [no] [yes]	[hh/dd/mm/yy] ["] ["]	[hh/dd/mm/yy] ["] ["]
[name/number 2]		[zone name]	[zone name]	[party 1] [party 2] [party n]	[sc id 1] [sc id 2] [sc id n]	[er] [ncr] [er]	[MW] ["] ["]	[MW] ["] ["]	[MW] ["] ["]	[1400]	[20] [n/a] [20]	[yes] [no] [yes]	["] ["] ["]	["] ["] ["]
[name/number n]		[zone name]	[zone name]	[party 1] [party 2] [party n]	[sc id 1] [sc id 2] [sc id n]	[er] [ncr] [er]	[MW] ["] ["]	[MW] ["] ["]	[MW] ["] ["]	[1500]	[20] [n/a] [20]	[yes] [no] [yes]	["] ["] ["]	["] ["] ["]

(o) Non-Emergency Curtailments
 [If other than pro rata, attach spreadsheet for ISO to use in allocating curtailments to rights holders between the indicated Zones. Otherwise, indicate "pro rata here.]

(p) Emergency Curtailments
 [Describe special procedures/requirements here. Indicate "N/A" if none.]

/1/ Priorities for firm and conditional firm transmission service are indicated in Schedules using Adjustment Bids as described in the SP.

ISO TARIFF APPENDIX N
Settlements and Billing

PART A
[Not Used]

PART B

GRID OPERATIONS CHARGE COMPUTATION

B 1 Purpose of charge

The Grid Operations Charge is a charge which recovers Redispatch costs incurred due to Intra-Zonal Congestion pursuant to Section 27.1.3 of the ISO Tariff. The Grid Operations Charge is paid by or charged to Scheduling Coordinators in order for the ISO to recover and properly redistribute the costs of adjusting the Balanced Schedules submitted by Scheduling Coordinators.

B 2 Fundamental formulae

B 2.1 Payments to Scheduling Coordinators with incremented schedules

When it becomes necessary for the ISO to increase the output of a Scheduling Coordinator's Generating Unit_i or System Resource_i, or reduce a Curtailable Demand_i in order to relieve Congestion within a Zone, the ISO will pay the Scheduling Coordinator. The amount that ISO pays the Scheduling Coordinator_j is the price specified in the Scheduling Coordinator's Imbalance Energy bid for the Generating Unit_i or System Resource_i, or Curtailable Demand_i multiplied by the quantity of Energy Dispatched. The formula for calculating the payment to Scheduling Coordinator_j for each block_b of Energy of its bid curve in Trading Interval_t is:

$$INC_{bijt} = adjinc_{bijt} * \Delta inc_{bijt}$$

B 2.1.1 Total Payment for Trading Interval

The formula for calculating payment to Scheduling Coordinator_j whose Generating Unit_i or System Resource_i has been increased or Curtailable Demand_i reduced for all the relevant blocks_b of Energy in the Imbalance Energy bid curve of that Generating Unit or System Resource or Curtailable Demand in the same Trading Interval_t is:

$$PayTI_{ijt} = \sum_b INC_{bijt}$$

B 2.2 Charges to Scheduling Coordinators with decremented schedules

When it becomes necessary for the ISO to decrease the output of a Scheduling Coordinator's Generating Unit_i or System Resource_i, in order to relieve Congestion within a Zone, the ISO will make a charge to the Scheduling Coordinator. The amount that the ISO will charge Scheduling Coordinator_j for decreasing the output of Generating Unit_i is

the decremental reference price specified for the Scheduling Coordinator as determined in accordance with Section 27.1.1.6.1 multiplied by the quantity of Energy Dispatched. The amount that the ISO will charge Scheduling Coordinator_j for decreasing the output of System Resource_i is the price specified in the Scheduling Coordinator's Imbalance Energy bid for System Resource_i multiplied by the quantity of Energy Dispatched. The formula for calculating the charge to Scheduling Coordinator_j for each block_b of Energy in its decremental reference price or Imbalance Energy Bid in Trading Interval_t is:

$$DEC_{bijt} = adjdec_{bijt} * \Delta dec_{bijt}$$

B 2.2.1 Total Charge for Trading Interval

The formula for calculating the charge to Scheduling Coordinator_j whose Generating Unit_i or System Resource_i has been decreased for all the relevant blocks_b of Energy at the decremental reference price for Generating Unit_i, or Imbalance Energy bid for System Resource_i in the same Trading Interval_t is:

$$ChargeTI_{ijt} = \sum_b DEC_{bijt}$$

B 2.3 Not Used

B 2.4 Net ISO Redispatch costs

The Trading Interval net Redispatch cost encountered by ISO to relieve Intra-Zonal Congestion is the sum of the amounts paid by the ISO to those Scheduling Coordinators whose Generation or System Resource was increased or Curtailable Demand was decreased during the Trading Interval less the sum of the amounts received by the ISO from those Scheduling Coordinators whose Generating Units or System Resource were decreased during the Trading Interval. The fundamental formula for calculating the net Redispatch cost is:

$$REDISP_{CONGt} = \sum_j PayTI_{ijt} - \sum_j ChargeTI_{ijt}$$

Note that $REDISP_{CONGt}$ can be either positive or negative. This means that it is possible for the ISO to generate either a net cost or a net income, for any given Trading Interval. In the event the ISO does not make use of equal amounts of incremental and decremental dispatched MWHs, then the net Redispatch cost becomes the sum of the amounts paid (or charged) by the ISO to those Scheduling Coordinators whose Generation or System Resource was increased (or decreased) or Curtailable Demand was decreased (or increased) during the Trading Interval less the sum of the amounts received by the ISO from Scheduling Coordinators through the Imbalance Energy Market.

B 2.5 Grid Operations Price

The grid operations price is the Trading Interval rate used by the ISO to apportion net Trading Interval Redispatch costs to Scheduling Coordinators within the Zone with Intra-

Zonal Congestion. The grid operations price is calculated using the following

formula:
$$GOP_t = \frac{REDISP_{CONG_t}}{\sum_j QCharge_{jt} + \sum_j Export_{jt}}$$

B 2.6 Grid Operations Charge

The Grid Operations Charge is the vehicle by which the ISO recovers the net Redispatch costs. It is allocated to each Scheduling Coordinator in proportion to the Scheduling Coordinator's Demand in the Zone with Intra-Zonal Congestion and exports from the Zone with Intra-Zonal Congestion. The formula for calculating the Grid Operations Charge for Scheduling Coordinator_j in Trading Interval_t is:

$$GOC_{jt} = GOP_t * (QCharge_{jt} + EXPORT_{jt})$$

B 3 Meaning of terms of formulae

B 3.1 INC_{bijt} - \$

The payment from the ISO due to Scheduling Coordinator_j whose Generating Unit_i or System Resource_i is increased or Curtailable Load_i is reduced within a block_b of Energy in its Imbalance Energy bid in Trading Interval_t in order to relieve Intra-Zonal Congestion.

B 3.2 adjinc_{bijt} - \$/MWh

The incremental cost for the rescheduled Generating Unit_i or System Resource_i or Curtailable Load_i taken from the relevant block_b of Energy in the Imbalance Energy bid submitted by the Scheduling Coordinator_j or generated by the ISO for the Trading Interval_t.

B 3.3 Δinc_{bijt} - MW

The amount by which the Generating Unit_i or System Resource_i or Curtailable Load_i of Scheduling Coordinator_j for Trading Interval_t is increased by the ISO within the relevant block_b of Energy in its Imbalance Energy bid.

B 3.4 PayT_{ijt} - \$

The Trading Interval payment to Scheduling Coordinator_j whose Generating Unit_i has been increased or System Resource_i or Curtailable Load_i reduced in Trading Interval_t of the Trading Day.

B 3.5 DEC_{bijt} - \$

The charge to Scheduling Coordinator_j whose Generating Unit_i or System Resource_i is decreased for Trading Interval_t within a block_b of Energy at the decremental reference price for Generating Unit_i or in the Imbalance Energy bid for System Resource_i.

B 3.6 adjdec_{bijt} - \$/MWh

The decremental cost for the rescheduled Generating Unit_i or System Resource_i, taken from the relevant block_b of Energy at the decremental reference price for Generating Unit_i or Imbalance Energy bid for System Resource_i, submitted by Scheduling Coordinator_j or generated by the ISO for the Trading Interval_t.

B 3.7 Δdec_{bij_t} - MW

The amount by which the Generating Unit_i or System Resource_i, of Scheduling Coordinator_j for Trading Interval_t is decreased by ISO within the relevant block_b of Energy at the decremental reference price for Generating Unit_i or Imbalance Energy bid for System Resource_i.

B 3.8 Charge_{Tlij_t} - \$

The Trading Interval charge to Scheduling Coordinator_j whose Generating Unit_i or System Resource_i has been decreased in Trading Interval_t of the Trading Day.

B 3.9 Not Used

B 3.10 Not Used

B 3.10.1 Not Used

B 3.10.2 Not Used

B 3.11 REDISPCONG_t - \$

The Trading Interval net cost to ISO to redispatch in order to relieve Intra-Zonal Congestion during Trading Interval_t.

B 3.12 GOP_t - \$/MWh

The Trading Interval grid operations price for Trading Interval_t used by the ISO to recover the costs of Redispatch for Intra-Zonal Congestion Management.

B 3.13 GOC_{jt} - \$

The Trading Interval Grid Operations Charge by the ISO for Trading Interval_t for Scheduling Coordinator_j in the relevant Zone with Intra-Zonal Congestion.

B 3.14 QCHARGE_{jt} – MWh

The Trading Interval metered Demand within a Zone for Trading Interval_t for Scheduling Coordinator_j whose Grid Operations Charge is being calculated.

B 3.15 EXPORT_{jt} – MWh

The total Energy for Trading Interval_t exported from the Zone to a neighboring Control Area by Scheduling Coordinator_j.

PART C

ANCILLARY SERVICES CHARGES COMPUTATION

C 1 Purpose of charges

The Ancillary Services charges reimburse the ISO for the costs of purchasing Ancillary Services in the Day-Ahead and Hour-Ahead Markets. Each Scheduling Coordinator that does not self-provide Ancillary Services must purchase these services from the ISO. The ISO will in turn purchase these Ancillary Services from Scheduling Coordinators in the markets. Ancillary Services purchased and resold by the ISO includes Regulation, Spinning Reserve, Non-Spinning Reserve, and Replacement Reserve. Any references in this Part C to the Ancillary Service "Regulation" shall be read as referring to "Regulation Up" or "Regulation Down".

This Part C also addresses the payments by ISO to Scheduling Coordinators for the Dispatch of energy from Dispatched Ancillary Services Units and for the Dispatch of Supplemental Energy in the Real Time Market. The ISO recovers the costs of real-time Dispatch of such energy through the Imbalance Energy charges described in Part D of this Appendix.

The reference to a Scheduling Coordinator by Zone refers to the Demand of that Scheduling Coordinator which is located in the Zone. A Generation Unit, Load, or System Resource located in another Control Area is considered to be located in the Zone in which its contract path enters the ISO Controlled Grid.

The ISO will purchase Ancillary Services for each Trading Interval in both the Day-Ahead and Hour-Ahead Markets. Separate payments will be calculated for each service for each Trading Interval and in each market for each Generating Unit, Load and System Resource. The ISO will then calculate a total payment for each Scheduling Coordinator for each Trading Interval for each service for each Zone in each market for all the Generating Units, Loads and System Resources that the Scheduling Coordinator represents. The ISO will charge Scheduling Coordinators for Ancillary Services, other than for energy, which they purchase from the ISO by calculating and applying charges to each Scheduling Coordinator for each Trading Interval for each service in each Zone in each market.

The ISO will allocate the Ancillary Services capacity charges, for both the Day-Ahead Market and the Hour-Ahead Market, on a Zonal basis if the Day-Ahead Ancillary Services Market is procured on a Zonal basis. The ISO will allocate the Ancillary Services capacity charges, for both the Day-Ahead Market and the Hour-Ahead Market, on an ISO Control Area wide basis if the Day-Ahead Ancillary Services Market is defined on an ISO Control Area wide basis.

C 2 Fundamental formulas

C 2.1 ISO payments to Scheduling Coordinators

C 2.1.1 Day-Ahead Market

- (a) Regulation. When the ISO purchases Regulation capacity in the Day-Ahead Market, Scheduling Coordinators for Generating Units that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit which provides Regulation capacity over a given Trading Interval will be the total quantity of Regulation capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. The required Regulation capacity is defined in Appendix A. Regulation Up and Regulation Down payments shall be calculated separately. This payment for Scheduling Coordinator j for providing Regulation Up capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCUpPayDA_{ijxt} = AGCUpQDA_{ijxt} * PAGCUpDA_{xt}$$

This payment for Scheduling Coordinator j for providing Regulation Down capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCDownPayDA_{ijxt} = AGCDownQDA_{ijxt} * PAGCDownDA_{xt}$$

The total Regulation Up payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$AGCUpPayTotalDA_{jxt} = \sum_i AGCUpPayDA_{ijxt}$$

The total Regulation Down payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$AGCDownPayTotalDA_{jxt} = \sum_i AGCDownPayDA_{ijxt}$$

- (b) Spinning Reserve. When ISO purchases Spinning Reserve capacity in the Day-Ahead Market. Scheduling Coordinators for Generating Units and System Resources that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit or

System Resource which provides Spinning Reserve capacity over a given Trading Interval will be the total quantity of Spinning Reserve capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. The required Spinning Reserve capacity is defined in Appendix A. This payment for Scheduling Coordinator j for providing Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$SpinPayDA_{ijxt} = SpinQDA_{ijxt} * PSpinDA_{xt}$$

The total Spinning Reserve payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$SpinPayTotalDA_{jxt} = \sum_i SpinPayDA_{ixt}$$

- (c) Non-Spinning Reserve. When the ISO purchases Non-Spinning Reserve capacity in the Day-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Non-Spinning Reserve capacity over a given Trading Interval will be the total quantity of Non-Spinning Reserve capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. The required Non-Spinning Reserve capacity is defined in Appendix A. This payment for Scheduling Coordinator j for providing Non-Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

(d) $NonSpinPayDA_{ijxt} = NonSpinQDA_{ijxt} * PNonSpinDA_{xt}$

The total Non-Spinning Reserve payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$NonSpinPayTotalDA_{jxt} = \sum_i NonSpinPayDA_{ixt}$$

- (d) Replacement Reserve. When the ISO purchases Replacement Reserve capacity in the Day-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payments for each Trading Interval of the Day-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Replacement Reserve capacity over a given Trading Interval will be the total

quantity of Replacement Reserve capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. The required Replacement Reserve capacity is defined in Appendix A. This payment for Scheduling Coordinator j for providing Replacement Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$ReplPayDA_{ijxt} = ReplQDA_{ijxt} * PReplDA_{xt}$$

The total Replacement Reserve payment to each Scheduling Coordinator for a given Trading Interval in the Day-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$ReplPayTotalDA_{jxt} = \sum_i ReplPayDA_{ijxt}$$

C 2.1.2 Hour-Ahead Market

- (a) **Regulation.** When the ISO purchases Regulation capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units that provide this capacity will receive payment for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit which provides Regulation capacity over the Trading Interval will be the total quantity of Regulation capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. The required Regulation capacity is defined in Appendix A. Regulation Up and Regulation Down payments shall be calculated separately. This payment for Scheduling Coordinator j for providing Regulation Up capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCUpPayHA_{ijxt} = AGCUpQIHA_{ijxt} * PAGCUpHA_{xt}$$

This payment for Scheduling Coordinator j for providing Regulation Down capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCDownPayHA_{ijxt} = AGCDownQIHA_{ijxt} * PAGCDownHA_{xt}$$

When a Scheduling Coordinator buys back, in the Hour-Ahead Market, Regulation capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Regulation capacity bought back times the Zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Regulation Up capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCUpReceiveHA_{ijxt} = AGCUpQDHA_{ijxt} * PAGCUpHA_{xt}$$

This payment to the ISO from Scheduling Coordinator j to buy back Regulation Down capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$AGCDownReceiveHA_{ijxt} = AGCDownQDHA_{ijxt} * PAGCDownHA_{xt}$$

The total Regulation payment for the Trading Interval of the Hour-Ahead Market to each Scheduling Coordinator for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Regulation bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$AGCDownPayTotalHA_{jxt} = \sum_i AGCDownPayHA_{ijxt} - \sum_i AGCDownReceiveHA_{ijxt}$$

$$AGCUpPayTotalHA_{jxt} = \sum_i AGCUpPayHA_{ijxt} - \sum_i AGCUpReceiveHA_{ijxt}$$

- (b) Spinning Reserve. When the ISO purchases Spinning Reserve capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units and System Resources that provide this capacity will receive payments for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit or System Resource which provides Spinning Reserve capacity over the Trading Interval will be the total quantity of Spinning Reserve capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. This payment for Scheduling Coordinator j for providing Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$SpinPayHA_{ijxt} = SpinQIHA_{ijxt} * PSpinHA_{xt}$$

When a Scheduling Coordinator buys back in the Hour-Ahead Market Spinning Reserve capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Spinning Reserve capacity bought back times the Zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$SpinReceiveHA_{ijxt} = SpinQDHA_{ijxt} * PSpinHA_{xt}$$

The total Spinning Reserve payment to each Scheduling Coordinator for the Trading Interval of the Hour-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Spinning Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$SpinPayTotalHA_{jxt} = \sum_i SpinPayHA_{ijxt} - \sum_i SpinReceiveHA_{ijxt}$$

- (c) Non-Spinning Reserve. When the ISO purchases Non-Spinning Reserve capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payment for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Non-Spinning Reserve capacity over the Trading Interval will be the total quantity of Non-Spinning Reserve capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. This payment for Scheduling Coordinator j for providing Non-Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$NonSpinPayHA_{ijxt} = NonSpinQIHA_{ijxt} * PNonSpinHA_{xt}$$

When a Scheduling Coordinator buys back in the Hour-Ahead Market Non-Spinning Reserve capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Non-Spinning Reserve capacity bought back times the Zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Non-Spinning Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$NonSpinReceiveHA_{ijxt} = SpinQDHA_{ijxt} * PNonSpinHA_{xt}$$

The total Non-Spinning Reserve payment to each Scheduling Coordinator for the Trading Interval of the Hour-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling

Coordinator to the ISO for Non-Spinning Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$NonSpinPayTotalHA_{jxt} = \sum_i NonSpinPayHA_{ijxt} - \sum_i NonSpinReceiveHA_{ijxt}$$

- (d) Replacement Reserve. When the ISO purchases Replacement Reserve capacity in the Hour-Ahead Market, Scheduling Coordinators for Generating Units, Loads and System Resources that provide this capacity will receive payments for the Trading Interval of the Hour-Ahead Market. The payment for a given Generating Unit, Load or System Resource which provides Replacement Reserve capacity over the Trading Interval will be the total quantity of Replacement Reserve capacity provided times the Zonal Market Clearing Price for that Trading Interval in that Zone. This payment for Scheduling Coordinator j for providing Replacement Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$ReplPayHA_{ijxt} = ReplQIHA_{ijxt} * PReplHA_{xt}$$

When a Scheduling Coordinator buys back in the Hour-Ahead Market Replacement Reserve capacity which it sold to the ISO in the Day-Ahead Market, the payment which the ISO receives will be the total quantity of Replacement Reserve capacity bought back times the Zonal Hour-Ahead Market Clearing Price for that Trading Interval in that Zone.

This payment to the ISO from Scheduling Coordinator j to buy back Replacement Reserve capacity from a resource i in Zone x for Trading Interval t is calculated as follows:

$$ReplReceiveHA_{ijxt} = ReplQDHA_{ijxt} * PReplHA_{xt}$$

The total Replacement Reserve payment to each Scheduling Coordinator for the Trading Interval of the Hour-Ahead Market for all the resources that it represents in a given Zone is calculated by summing all the payments for the resources of the Scheduling Coordinator in the Zone for the Trading Interval and then deducting therefrom any amount payable by the Scheduling Coordinator to the ISO for Replacement Reserve bought back by the Scheduling Coordinator from the ISO in the Hour-Ahead Market for the Trading Interval on behalf of resources located in the Zone. This payment for Scheduling Coordinator j in Zone x for Trading Interval t is calculated as follows:

$$ReplPayTotalHA_{jxt} = \sum_i ReplPayHA_{ijxt} - \sum_i ReplReceiveHA_{ijxt}$$

C 2.2 ISO allocation of charges to Scheduling Coordinators

C 2.2.1 Day-Ahead Market

- (a) Regulation. The ISO will charge the Zonal cost of providing Regulation capacity that is not self-provided by Scheduling Coordinators, in the Day-Ahead Market, through the application of a charge to each Scheduling Coordinator for each Trading Interval. This charge will be computed by multiplying the Regulation user rate for the Trading Interval by the Scheduling Coordinator's Regulation obligation, for which it has not self-provided, for the same period.

The Zonal Regulation user rate for the Day-Ahead Market is calculated by dividing the total cost to ISO of purchasing Regulation Capacity within the Zone, for the Trading Interval, by the total ISO Regulation MW purchases for the Trading Interval within the Zone. Regulation Up and Regulation Down payments shall be calculated separately.

The Day-Ahead Regulation Up user rate in Zone x for Trading Interval t is calculated as follows:

$$AGCUpRateDA_{xt} = \frac{\sum_j AGCUpPayTotalDA_{jxt}}{AGCUpPurchDA_{xt}}$$

where,

$AGCUpPayTotalDA_{jxt}$ = Total Regulation Up payments for the Settlement Period t in the Day-Ahead Market for the Zone x.

The Day-Ahead Regulation Down user rate in Zone x for Trading Interval t is calculated as follows:

$$AGCDownRateDA_{xt} = \frac{\sum_j AGCDownPayTotalDA_{jxt}}{AGCDownPurchDA_{xt}}$$

where,

$AGCDownPayTotalDA_{jxt}$ = Total Regulation Down payments for the Settlement Period t in the Day-Ahead Market for the Zone x.

The Regulation capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$AGCUpChgDA_{jxt} = AGCUpOblig_{jxt} * AGCUpRateDA_{xt}$$

$$AGCDownChgDA_{jxt} = AGCDownOblig_{jxt} * AGCDownRateDA_{xt}$$

- (b) Spinning Reserve. The ISO will charge the Zonal cost of providing Spinning Reserve capacity that is not self-provided by Scheduling Coordinators, in the Day-Ahead Market, through the application of a charge to each Scheduling

Coordinator for each Trading Interval. This charge will be computed by multiplying the Spinning Reserve capacity user rate for the Trading Interval by the Scheduling Coordinator's Spinning Reserve obligation, for which it has not self-provided, for the same period. The Zonal Spinning Reserve capacity user rate for the Day-Ahead Market is calculated by dividing the total cost to ISO of purchasing Spinning Reserve capacity within the Zone, for the Trading Interval, by the total ISO Spinning Reserve MW purchases for the Trading Interval within the Zone. The Day-Ahead Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$SpinRateDA_{xt} = \frac{\sum_j SpinPayTotalDA_{jxt}}{SpinPurchDA_{xt}}$$

The Spinning Reserve capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$SpinChgDA_{jxt} = SpinOblig_{jxt} * SpinRateDA_{xt}$$

- (c) Non-Spinning Reserve. The ISO will charge the Zonal cost of providing Non-Spinning Reserve capacity that is not self-provided by Scheduling Coordinators, in the Day-Ahead Market, through the application of a charge to each Scheduling Coordinator for each Trading Interval. This charge will be computed by multiplying the Non-Spinning Reserve capacity user rate for the Trading Interval by the Scheduling Coordinator's Non-Spinning Reserve obligation, for which it has not self-provided, for the same period.

The Zonal Non-Spinning Reserve capacity user rate for the Day-Ahead Market is calculated by dividing the total cost to ISO of purchasing Non-Spinning Reserve capacity within the Zone, for the Trading Interval, by the total ISO Non-Spinning Reserve MW purchases for the Trading Interval within the Zone. The Day-Ahead Non-Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$NonSpinRateDA_{xt} = \frac{\sum_j NonSpinPayTotalDA_{jxt}}{NonSpinPurchDA_{xt}}$$

The Non-Spinning Reserve capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$NonSpinChgDA_{jxt} = NonSpinOblig_{jxt} * NonSpinRateDA_{xt}$$

C 2.2.2 Hour-Ahead Market

- (a) Regulation. The ISO will charge the Zonal net cost of providing Regulation capacity that is not self-provided by Scheduling Coordinators, in the Hour-Ahead Market through the application of a charge to each Scheduling Coordinator for the Trading Interval concerned. This charge will be computed by multiplying the Regulation user rate for the Trading Interval by the Scheduling Coordinator's Regulation obligation, for which it has not self-provided, for the same period.

The Zonal Regulation capacity user rate for the Hour-Ahead Market is calculated by dividing the total cost to the ISO of purchasing Regulation capacity within the Zone less any amounts payable to the ISO by Scheduling Coordinators for Regulation bought back from the ISO in the Hour-Ahead Market on behalf of resources located in the Zone, for the Trading Interval, by the total ISO Regulation capacity MW purchases for the Trading Interval within the Zone. Regulation Up and Down payments shall be calculated separately. The Hour-Ahead Regulation Up capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$AGCUpRateHA_{xt} = \frac{\sum_j AGCUpPayTotalHA_{jxt}}{AGCUpPurchHA_{xt}}$$

where,

$AGCUpPayTotalHA_{jxt}$ = Total Regulation Up payments for the Settlement Period t in the Hour-Ahead Market for Zone x.

The Hour-Ahead Regulation Down capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$AGCDownRateHA_{xt} = \frac{\sum_j AGCDownPayTotalHA_{jxt}}{AGCDownPurchHA_{xt}}$$

where,

$AGCDownPayTotalHA_{jxt}$ = Total Regulation Down payments for the Settlement Period t in the Hour-Ahead Market for Zone x.

The Regulation capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$AGCUpChgHA_{jxt} = (AGCUpOblig_{jxt} * AGCUpRateHA_{xt})$$

$$AGCDownChgHA_{jxt} = (AGCDownOblig_{jxt} * AGCDownRateHA_{xt})$$

- (b) Spinning Reserve. The ISO will charge the Zonal net cost of providing Spinning Reserve capacity that is not self-provided by Scheduling Coordinators, in the Hour-Ahead Market, through the application of a charge to each Scheduling Coordinator for the Trading Interval. This charge will be computed by multiplying the Spinning Reserve capacity user rate for the Trading Interval by the Scheduling Coordinator's Spinning Reserve obligation, for which it has not self-provided, for the same period. The Zonal Spinning Reserve capacity user rate for the Hour-Ahead Market is calculated by dividing the total cost to ISO of purchasing Spinning Reserve capacity within the Zone less any amounts payable to the ISO by Scheduling Coordinators for Spinning Reserve bought back from the ISO in the Hour-Ahead Market on behalf of resources located in the Zone, for the Trading Interval, by the total ISO Spinning Reserve MW purchases for the Trading Interval within the Zone. The Hour-Ahead Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$SpinRateHA_{xt} = \frac{\sum_j SpinPayTotalHA_{jxt}}{SpinPurchHA_{xt}}$$

The Spinning Reserve capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$SpinChgHA_{jxt} = (SpinOblig_{jxt} * SpinRateHA_{xt})$$

- (c) Non-Spinning Reserve. The ISO will charge the Zonal net cost of providing Non-Spinning Reserve capacity that is not self-provided by Scheduling Coordinators, in the Hour-Ahead Market, through the application of a charge to each Scheduling Coordinator for the Trading Interval. This charge will be computed by multiplying the Non-Spinning Reserve capacity user rate for the concerned Trading Interval by the Scheduling Coordinator's Non-Spinning Reserve obligation, for which it has not self-provided, for the same period. The Zonal Non-Spinning Reserve capacity user rate for the Hour-Ahead Market is calculated by dividing the total cost to ISO of purchasing Non-Spinning Reserve capacity within the Zone less any amounts payable to the ISO by Scheduling Coordinators for Non-Spinning Reserve bought back from the ISO in the Hour-Ahead Market on behalf of resources in the Zone, for the Trading Interval, by the total ISO Non-Spinning Reserve MW purchases for the Trading Interval within the Zone. The Hour-Ahead Non-Spinning Reserve capacity user rate in Zone x for Trading Interval t is calculated as follows:

$$NonSpinRateHA_{xt} = \frac{\sum_j NonSpinPayTotalHA_{jxt}}{NonSpinObligTotal_{xt}}$$

The Non-Spinning Reserve capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t is calculated as follows:

$$NonSpinChgHA_{jxt} = (NonSpinOblig_{jxt} * NonSpinRateHA_{xt})$$

C 2.2.3 Replacement Reserve

The user rate per unit of Replacement Reserve obligation for each Settlement Period t for each Zone x shall be as follows:

$$ReplRate_{xt} = \frac{(PRepResDA_{xt} * OrigReplReqDA_{xt}) + (PRepResHA_{xt} * OrigReplReqHA_{xt})}{OrigReplReqDA_{xt} + OrigReplReqHA_{xt}}$$

where:

OrigReplReqDA_{xt} = Replacement Reserve requirement net of self-provision in the Day-Ahead Market before consideration of any substitutions pursuant to Section 8.2.3.6.

OrigReplReqHA_{xt} = Incremental change in the Replacement Reserve requirement net of self-provision between the Day-Ahead Market and the Hour-Ahead Market before consideration of any substitutions pursuant to Section 8.2.3.

PRepResDA_{xt} is the Market Clearing Price for Replacement Reserve in the Day-Ahead Market for Zone x in Settlement Period t.

PRepResHA_{xt} is the Market Clearing Price for Replacement Reserve in the Hour-Ahead Market for Zone x in Settlement Period t.

For each Settlement Period t, each Scheduling Coordinator shall pay to the ISO a sum calculated as follows for each Zone x:

$$ReplRate_{xt} * ReplOblig_{jxt}$$

where

ReplOblig_{jxt} = *DevReplOblig_{jxt}* + *RemRepl_{jxt}* - *SelfProv_{jxt}* + *NetInterSCTrades_{jxt}* *DevReplOblig_{jxt}* is the Scheduling Coordinator's obligation for deviation Replacement Reserve in Zone x in the Settlement Period t and *RemRepl_{jxt}* is the Scheduling Coordinator's obligation for remaining Replacement Reserve in Zone x for Settlement Period t.

SelfProv_{jxt} is Scheduling Coordinator's Replacement Reserve self-provision in Zone x for Settlement Period t.

NetInterSCTrades_{jxt} is the sale of Replacement Reserve less the purchase of Replacement Reserve through Inter-Scheduling Coordinator Trades by Scheduling Coordinator j in Zone x for Settlement Period t.

Deviation Replacement Reserve for Scheduling Coordinator i in Zone x for Settlement Period t is calculated as follows:

If $ReplObligTotal_{xt} > TotalDeviations_{xt}$ then:

$$DevReplOblig_{ijt} = \left[\text{Max} \left(0, \sum_i GenDev_{ijxt} \right) - \text{Min} \left(0, \sum_i LoadDev_{ijxt} \right) \right]$$

If $ReplObligTotal_{xt} < TotalDeviations_{xt}$ then:

$$DevReplOblig_{ijt} = \frac{ReplObligTotal_{xt}}{TotalDeviations_{xt}} * \left[\text{Max} \left(0, \sum_i GenDev_{ijxt} \right) - \text{Min} \left(0, \sum_i LoadDev_{ijxt} \right) \right]$$

where,

$$TotalDeviations_{xt} = \sum_j \left[\text{Max} \left(0, \sum_i GenDev_{ijxt} \right) - \text{Min} \left(0, \sum_i LoadDev_{ijxt} \right) \right] GenDev_{ijxt}$$

= The deviation between scheduled and actual Energy generation for Generator i represented by Scheduling Coordinator I in Zone x during Settlement Period t as referenced in SABP Part D.

$LoadDev_{ijxt}$ = The deviation between scheduled and actual Load consumption for resource I represented by Scheduling Coordinator in Zone x during Settlement Period t as referenced in SABP Part D.

$DevReplOblig_{xt}$ is total deviation Replacement Reserve in Zone x for Settlement Period t.

$ReplObligTotal_{xt}$ is total Replacement Reserve Obligation in Zone x for Settlement Period t.

Remaining Replacement Reserve for Scheduling Coordinator j in Zone x for Settlement Period t is calculated as follows:

$$RemRepl_{xjt} = \frac{MeteredDemand_{jxt}}{TotalMeteredDemand_{xt}} * TotalRemRepl_{xt}$$

where:

$MeteredDemand_{jxt}$ is the Scheduling Coordinator's total metered Demand excluding exports in Zone x for Settlement Period t.

$TotalMeteredDemand_{xt}$ is total metered Demand excluding exports in Zone x for Settlement Period t.

$$TotalRemRepl_{xt} = \text{Max}[0, ReplObligTotal_{xt} - DevReplOblig_{xt}]$$

C 2.2.4 Rational Buyer Adjustments

- (a) If, in any Settlement Period, no quantity of Regulation, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve is purchased in the Day-Ahead Market or the Hour-Ahead Market due to the operation of Section 8.2.3.6 of the ISO Tariff, then in lieu of the user rate determined in accordance with Section C 2.2.1, C 2.2.2, or C 2.2.3, as applicable, the user rate for the affected Ancillary Service for that Settlement Period shall be determined as follows:
- (i) If the affected market is a Day-Ahead Market, the user rate for the affected Ancillary Service shall be set at the lowest capacity reservation price for an unaccepted qualified capacity bid in a Day-Ahead Market for that Ancillary Service or for another Ancillary Service that meets the requirements for the affected Ancillary Service. If there are no such unaccepted bids, the user rate for the affected Ancillary Service shall be the lowest Market Clearing Price for the same Settlement Period established in the Day-Ahead Market for another Ancillary Service that meets the requirements for the affected Ancillary Service.
 - (ii) If the affected market is an Hour-Ahead Market, the user rate for the affected Ancillary Service shall be set at the lowest capacity reservation price for an unaccepted qualified capacity bid in the Hour-Ahead Market for the same Settlement Period for that Ancillary Service or for another Ancillary Service that meets the requirements for the affected Ancillary Service. If there are no such unaccepted bids, the user rate for the affected Ancillary Service shall be the user rate for the same Ancillary Service in the Day-Ahead Market in the same Settlement Period.
- (b) With respect to each Settlement Period, in addition to the user rates determined in accordance with Sections C 2.2.1 through C 2.2.3, or Section C 2.2.4(a), as applicable, each Scheduling Coordinator shall be charged an additional amount equal to its proportionate share, based on total purchases by Scheduling Coordinators of Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve of the amount, if any, by which (i) the total payments to Scheduling Coordinators pursuant to Section C 2.1 for the Day-Ahead Market and Hour-Ahead Market and all Zones, exceed (ii) the total amounts charged to Scheduling Coordinators pursuant to Sections C 2.2.1 through C 2.2.3, for the Day-Ahead Market and Hour-Ahead Market and all Zones. If total amounts charged to Scheduling Coordinators exceed the total payments to Scheduling Coordinators, each Scheduling Coordinator will be refunded its proportionate share, based on total purchases by Scheduling Coordinators of Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve.

C 2.2.5 Real-Time Market

- (a) The ISO will charge the costs of purchasing Instructed Imbalance Energy output from Dispatched Spinning Reserve, Non-Spinning Reserve, Replacement Reserve and Supplemental Energy resources through the Instructed Imbalance Energy settlement process.

- (b) The ISO will charge the costs of purchasing Uninstructed Imbalance Energy (including incremental and decremental Energy from Generating Units providing Regulation) through the Uninstructed Imbalance Energy settlement process.
- (c) The ISO will charge the costs of Regulation Energy Payment Adjustments as calculated in accordance with Section 8.11.5 of the ISO Tariff, in accordance with Section 11.2.9.

C 3 Meaning of terms of formulae

C 3.1 AGCUpPayDA_{ijxt} - \$

The payment for Scheduling Coordinator j for providing Regulation Up capacity in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

AGCDownPayDA_{ijxt} - \$

The payment for Scheduling Coordinator j for providing Regulation Down capacity in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.2 AGCUpQDA_{ijxt} – MW

The total quantity of Regulation Up capacity provided in the ISO Day-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

AGCDownQDA_{ijxt} – MW

The total quantity of Regulation Down capacity provided in the ISO Day-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.3 PAGCUpDA_{xt} - \$/MW

In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those Units subject to the cap for Regulation Up Capacity in the Day-Ahead Market for Trading Interval t in Zone x. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 8.7, the bid price for the unit for Regulation Up Capacity in Zone x for Trading Interval t.

PAGCDownDA_{xt} - \$/MW

In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those Units subject to the cap for Regulation Down Capacity in the Day-Ahead Market for Trading Interval t in Zone x. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 8.7, the bid price for the unit for Regulation Down Capacity in Zone x for Trading Interval t.

C 3.4 AGCUpPayTotalDAjxt - \$

The total payment for Regulation Up capacity to Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

AGCDownPayTotalDAjxt - \$

The total payment for Regulation Down capacity to Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.5 AGCUpPayHAijxt - \$

The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Regulation Up capacity in the Hour-Ahead Market from a resource i in Zone x for Trading Interval t.

AGCDownPayHAijxt - \$

The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Regulation Down capacity in the Hour-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.5.1 AGCUpReceiveHAijxt - \$

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead Regulation Up capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

AGCDownReceiveHAijxt - \$

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead Regulation Down capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.6 AGCUpQIHAijxt – MW

The total quantity of incremental (additional to Day-Ahead) Regulation Up capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

AGCDownQIHAijxt – MW

The total quantity of incremental (additional to Day-Ahead) Regulation Down capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.7 AGCUpQDHA_{ijxt} – MW

The total quantity of decremental (less than Day-Ahead) Regulation Up capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

AGCDownQDHA_{ijxt} – MW

The total quantity of decremental (less than Day-Ahead) Regulation Down capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.7.1 PAGCUpHA_{xt} - \$/MW

The Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Regulation Up capacity in the Hour-Ahead Market for Trading Interval t in Zone x. On buyback condition, MCP applies.

PAGCDownHA_{xt} - \$/MW

The Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Regulation Down capacity in the Hour-Ahead Market for Trading Interval t in Zone x. On buyback condition, MCP applies.

C 3.8 AGCUpPayTotalHA_{jxt} - \$

The total payment for incremental (additional to Day-Ahead) Regulation Up capacity to Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Regulation Up capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

AGCDownPayTotalHA_{jxt} - \$

The total payment for incremental (additional to Day-Ahead) Regulation Down capacity to Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Regulation Down capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.9 AGCUpRateDA_{xt} - \$/MW

The Day-Ahead Regulation Up capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

AGCDownRateDA_{xt} - \$/MW

The Day-Ahead Regulation Down capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.10 AGCUpObligTotal_{xt} – MW

The net total Regulation Up obligation in Zone x for Trading Interval t as defined in Appendix A. This net total equals the total obligation minus that self-provided.

AGCDownObligTotal_{xt} – MW

The net total Regulation Down obligation in Zone x for Trading Interval t as defined in Appendix A. This net total equals the total obligation minus that self-provided.

C 3.11 AGCUpChgDA_{jxt} - \$

The Regulation Up charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

AGCDownChgDA_{jxt} - \$

The Regulation Down charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.12 AGCUpOblig_{jxt} – MW

The net Regulation Up obligation for Scheduling Coordinator j in Zone x for Trading Interval t as defined in Appendix A. This net obligation equals the obligation minus that self-provided.

AGCDownOblig_{jxt} – MW

The net Regulation Down obligation for Scheduling Coordinator j in Zone x for Trading Interval t as defined in Appendix A. This net obligation equals the obligation minus that self-provided.

C 3.13 AGCUpRateHA_{xt} - \$/MW

The Hour-Ahead incremental (additional to Day-Ahead) Regulation Up capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

AGCDownRateHA_{xt} - \$/MW

The Hour-Ahead incremental (additional to Day-Ahead) Regulation Down capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.14 AGCUpChgHAjxt - \$

The incremental (additional to Day-Ahead) Regulation Up charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t.

AGCDownChgHAjxt - \$

The incremental (additional to Day-Ahead) Regulation Down charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t.

C 3.15 EnQPayijxt - \$

The payment for Scheduling Coordinator j for Instructed Imbalance Energy output from a resource i in the Real Time Market in Zone x for Trading Interval t.

C 3.16 [NOT USED]

C 3.17 [NOT USED]

C 3.18 [NOT USED]

C 3.19 SpinPayDAijxt - \$

The payment for Scheduling Coordinator j for providing Spinning Reserve capacity in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.20 SpinQDAijxt – MW

The total quantity of Spinning Reserve capacity provided in the Day-Ahead Market by resource i represented by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.20A REPAijxt - \$

The Regulation Energy Payment Adjustment payable for real-time incremental or decremental Energy provided from Regulation resource i of Scheduling Coordinator j in Zone x in Trading Interval t.

C 3.20B RUPijxt – MW

The upward Regulation capacity of Regulation resource i in Zone x included in the Final Schedule for Ancillary Services of Scheduling Coordinator j for Trading Interval t, weighted in proportion to the ISO's need for upward Regulation.

C3.20C RDNijxt – MW

The downward Regulation capacity of Regulation resource i in Zone x included in the Final Schedule for Ancillary Services of Scheduling Coordinator j for Trading Interval t, weighted in proportion to the ISO's need for downward Regulation.

C 3.20D CUP – number

The constant established by the ISO and subject to change by resolution of the ISO Governing Board. Initially this shall be set at 1. The ISO may modify the value of CUP within a range of 0-1 either generally in regard to all hours or specifically in regard to particular times of the day, after the ISO Governing Board approves such modifications, by a notice issued by the Chief Executive Officer of the ISO and posted on the ISO Internet "Home Page," at <http://www.caiso.com>, or such other Internet address as the ISO may publish from time to time, specifying the date and time from which the modification shall take effect, which shall be not less than seven (7) days after the Notice is issued.

C 3.20E CDN – number

The constant established by the ISO and subject to change by resolution of the ISO Governing Board. Initially this shall be set at 1. The ISO may modify the value of CDN within a range of 0-1 either generally in regard to all hours or specifically in regard to particular times of the day, after the ISO Governing Board approves such modifications, by a notice issued by the Chief Executive Officer of the ISO and posted on the ISO Internet "Home Page," at <http://www.caiso.com>, or such other Internet address as the ISO may publish from time to time, specifying the date and time from which the modification shall take effect, which shall be not less than seven (7) days after the Notice is issued.

C 3.21 PSpinDA_{xt} -\$/MW

In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Day-Ahead Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for Spinning Reserve Capacity in Zone x for Trading Interval t. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 8.7, the bid price for the unit for Spinning Reserve Capacity in Zone x for Trading Interval t.

C 3.22 SpinPayTotalDA_{jxt} - \$

The total payment to Scheduling Coordinator j for Spinning Reserve capacity in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.23 SpinPayHA_{jxt} - \$

The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Spinning Reserve capacity in the Hour-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.23.1 SpinReceiveHA_{jxt} - \$

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.24 SpinQIH_{ijxt} – MW

The total quantity of incremental (additional to Day-Ahead) Spinning Reserve capacity provided in the Hour-Ahead Market by resource i represented by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.25 SpinQDHA_{ijxt} – MW

The total quantity of decremental (less than Day-Ahead) Spinning Reserve capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.25.1 PSpinHA_{xt} -\$/MW

The Hour-Ahead Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Spinning Reserve capacity in Zone x for Trading Interval t. On Buyback condition, MCP applies charge for HA.

C 3.26 SpinPayTotalHA_{jxt} - \$

The total payment to Scheduling Coordinator j for incremental (additional to Day-Ahead) Spinning Reserve capacity in the Hour-Ahead Market in Zone x for Trading Interval t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.27 SpinRateDA_{xt} - \$/MW

The Day-Ahead Spinning Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.28 SpinObligTotal_{xt} – MW

The net total Spinning Reserve capacity obligation in Zone x for Trading Interval t as defined in Appendix A. This net total equals the total obligation minus that self-provided.

C 3.29 SpinChgDA_{jxt} - \$

The Spinning Reserve capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.30 SpinOblig_{jxt} – MW

The net Spinning Reserve capacity obligation for Scheduling Coordinator j in Zone x for Trading Interval t as defined in Appendix A. This net obligation equals the obligation minus that self-provided.

C 3.31 SpinRateHA_{xt} - \$/MW

The Hour-Ahead incremental (additional to Day-Ahead) Spinning Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.32 SpinChgHA_{jxt} - \$

The incremental (additional to Day-Ahead) Spinning Reserve capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t.

C 3.33 NonSpinPayDA_{ijxt} - \$

The payment for Scheduling Coordinator j for providing Non-Spinning Reserve capacity in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.34 NonSpinQDA_{ijxt} - MW

The total quantity of Non-Spinning Reserve capacity provided from resource i in the Day-Ahead Market by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.35 PNonSpinDA_{xt} - \$/MW

In the case of Capacity made available in accordance with the ISO's Final Day-Ahead Schedules, the Day-Ahead Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for Non-Spinning Reserve Capacity for Trading Interval t in Zone x. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 8.7, the bid price for the unit for Non-Spinning Reserve Capacity in Zone x for Trading Interval t.

C 3.36 NonSpinPayTotalDA_{jxt} - \$

The total payment to Scheduling Coordinator j for providing Non-Spinning Reserve capacity in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.37 NonSpinPayHA_{ijxt} - \$

The payment for Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Non-Spinning Reserve capacity in the Hour-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.37.1 NonSpinReceiveHA_{ijxt} - \$

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Non-Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.38 NonSpinQIHajxt – MW

The total quantity of incremental (additional to Day-Ahead) Non-Spinning Reserve capacity provided from resource i in the Hour-Ahead Market by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.39 NonSpinQDHajxt – MW

The total quantity of decremental (less than Day-Ahead) Non-Spinning Reserve capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.39.1 PNonSpinHAxt - \$/MW

The Hour-Ahead Zonal Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units subject to the cap for incremental (additional to Day-Ahead) Non-Spinning Reserve capacity for Trading Interval t in Zone x. On Buyback condition, MCP applies.

C 3.40 NonSpinPayTotalHAjxt - \$

The total payment to Scheduling Coordinator j for providing incremental (additional to Day-Ahead) Non-Spinning Reserve capacity in the Hour-Ahead Market in Zone x for Trading Interval t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Non-Spinning Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead market in Zone x for Trading Interval t.

C 3.41 NonSpinRateDAxt - \$/MW

The Day-Ahead Non-Spinning Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.42 NonSpinObligTotalxt – MW

The net total Non-Spinning Reserve capacity obligation in Zone x for Trading Interval t as defined in Appendix A. This net total obligation equals the total minus that self-provided.

C 3.43 NonSpinChgDAjxt - \$

The Non-Spinning Reserve Capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.44 NonSpinObligjxt – MW

The net Non-Spinning Reserve capacity obligation for Scheduling Coordinator j in Zone x for Trading Interval t as defined in Appendix A. This net obligation is the obligation minus that self-provided.

C 3.45 NonSpinRateHA_{xt} - \$/MW

The Hour-Ahead incremental (additional to Day-Ahead) Non-Spinning Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.46 NonSpinChgHA_{jxt} - \$

The incremental (additional to Day-Ahead) Non-Spinning Reserve Capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t.

C 3.47 NonSpinObligHA_{jxt} – MW

The net incremental (additional to Day-Ahead) Non-Spinning Reserve capacity obligation in the Hour-Ahead Market for Scheduling Coordinator j in Zone x for Trading Interval t as defined in Appendix A. This net obligation is the obligation minus that self-provided.

C 3.48 ReplPayDA_{ijxt} - \$

The payment for Scheduling Coordinator j for providing Replacement Reserve capacity in the Day-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.49 ReplQDA_{ijxt} – MW

The total quantity of Replacement Reserve capacity provided in the Day-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.50 PReplDA_{xt} -\$/MW

In the case of Capacity made available in accordance with ISO's Final Day-Ahead Schedules, the Day-Ahead Market Clearing Price for units exempt from FERC Ancillary Service rate caps or the bid price for those units not subject to the cap for Replacement Reserve Capacity in Zone x for Trading Interval t. In the case of Capacity not included in the ISO's Final Day-Ahead Schedules but made available in accordance with amended Ancillary Services supplier schedules issued in accordance with Section 8.7, the bid price for the unit for Replacement Reserve Capacity in Zone x for Trading Interval t.

C 3.51 ReplPayTotalDA_{jxt} - \$

The total payment to Scheduling Coordinator j for providing Replacement Reserve capacity in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.51.1 ReplReceiveHA_{ijxt} - \$

The payment from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Replacement Reserve capacity which the ISO had purchased from Scheduling

Coordinator j in the Day-Ahead Market from a resource i in the Zone x for Trading Interval t.

C 3.52 ReplPayHA_{ijxt} - \$

The payment for Scheduling Coordinator j for providing of incremental (additional to Day-Ahead) Replacement Reserve capacity in the Hour-Ahead Market from a resource i in Zone x for Trading Interval t.

C 3.53 ReplQIHA_{ijxt} – MW

The total quantity of incremental (additional to Day-Ahead) Replacement Reserve capacity provided in the Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.54 ReplQDHA_{ijxt} – MW

The total quantity of decremental (less than Day-Ahead) Replacement Reserve capacity provided in the ISO Hour-Ahead Market from resource i by Scheduling Coordinator j in Zone x for Trading Interval t.

C 3.54.1 PReplHA_{xt} -\$/MW

The Hour-Ahead Market Clearing Price for Non-FERC jurisdictional units or the bid price for FERC jurisdictional units for incremental (additional to Day-Ahead) Replacement Reserve capacity in Zone x for Trading Interval t. On Buyback condition, MCP applies.

C 3.55 ReplPayTotalHA_{ijxt} - \$

The total payment to Scheduling Coordinator j for providing of incremental (additional to Day-Ahead) Replacement Reserve capacity in the Hour-Ahead Market in Zone x for Trading Interval t, after deduction of payments from Scheduling Coordinator j for buying back from the ISO in the Hour-Ahead, Replacement Reserve capacity which the ISO had purchased from Scheduling Coordinator j in the Day-Ahead Market in Zone x from Trading Interval t.

C 3.56 ReplRateDA_{xt} - \$/MW

The Day-Ahead Replacement Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.57 ReplChgDA_{ijxt} - \$

The Replacement Reserve capacity charge for Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

C 3.58 ReplRateHA_{xt} – \$/MW

The Hour-Ahead incremental (additional to Day-Ahead) Spinning Reserve capacity user rate charged to Scheduling Coordinators by the ISO in Zone x for Trading Interval t.

C 3.59 ReplChgHA_{jxt} - \$

The incremental (additional to Day-Ahead) Replacement Reserve capacity charge for Scheduling Coordinator j in the Hour-Ahead Market in Zone x for Trading Interval t.

C 3.60 ReplObligTotal_{xt} – MW

The net total Replacement Reserve capacity obligation in the Day-Ahead and Hour-Ahead Markets in Zone x for Trading Interval t as defined in Appendix A. This net total obligation is the total obligation minus that self-provided.

C 3.61 ReplPayTotal_{jxt} - \$

The total payment to Scheduling Coordinator j for providing Replacement Reserve capacity in the Day-Ahead and Hour-Ahead Markets in Zone x for Trading Interval t.

C 3.62 PavgRepl_{xt} - \$/MW

The average price paid for Replacement Reserve capacity in the Day-Ahead Market and the Hour-Ahead Market in Zone x in Trading Interval t.

C 3.63 UnDispReplChg_{jxt} - \$

The undispached Replacement Reserve Capacity charge for Scheduling Coordinator j in the Day-Ahead and Hour-Ahead Markets in Zone x for Trading Interval t.

C 3.64 ReplOblig_{jxt} – MW

The Replacement Reserve capacity obligation in the Day-Ahead and Hour-Ahead Markets for Scheduling Coordinator j in Zone x for Trading Interval t as defined in Appendix A.

C 3.65 ReplQDisp_{xt} – MWh

The Dispatched Replacement Reserve capacity in the Day-Ahead Market in Zone x in Trading Interval t.

C 3.66 AGCUpPurchDA_{xt} – MW

The total quantity of Regulation Up capacity provided in the Day-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.

AGCDownPurchDA_{xt} – MW

The total quantity of Regulation Down capacity provided in the Day-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.

C 3.67 SpinPurchDA_{xt} – MW

The total quantity of Spinning Reserve capacity provided in the Day-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.

C 3.68 NonSpinPurchDA_{xt} – MW

The total quantity of Non-Spinning Reserve capacity provided in the Day-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.

C 3.69 AGCUpPurchHA_{xt} – MW

The net quantity of Regulation Up capacity provided in the Hour-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.

AGCDownPurchHA_{xt} – MW

The net quantity of Regulation Down capacity provided in the Hour-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.

C 3.70 SpinPurchHA_{xt} – MW

The net quantity of Spinning Reserve capacity provided in the Hour-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.

C 3.71 NonSpinPurchDA_{xt} – MW

The net quantity of Non-Spinning Reserve capacity provided in the Hour-Ahead Market in Zone x for Trading Interval t, not including self-provided quantities.

PART D
IMBALANCE ENERGY CHARGE COMPUTATION

D 1 Purpose of charge

The Imbalance Energy charge is the term used for allocating the cost of not only the Imbalance Energy (the differences between scheduled and actual Generation and Demand), but also any Unaccounted for Energy (UFE) and any errors in the forecasted Transmission Losses as represented by the GMMs. Any corresponding cost of Dispatched Replacement Reserve Capacity that is not allocated as an Ancillary Service is also included along with the Imbalance Energy charge.

D 2 Fundamental formulae

D 2.1.1 Uninstructed Imbalance Energy Charges on Scheduling Coordinators

Uninstructed Imbalance Energy attributable to each Load Take-Out Point, Generating Unit, System Unit, or System Resource for which a Scheduling Coordinator has a Final Hour-Ahead Schedule or Metered Quantity, for each Settlement Interval shall be deemed to be sold or purchased, as the case may be, by the ISO and charges or payments for Uninstructed Imbalance Energy shall be settled by debiting or crediting, as the case may be, the Scheduling Coordinator with an amount for each Settlement Interval.

Uninstructed Imbalance Energy within a Settlement Interval shall be settled in two tiers that are defined in relation to the expected Energy associated with the Final Hour-Ahead Schedule, if any, and the Dispatch Instruction as follows:

- 1) Deviations from the expected Energy associated with a Dispatch Instruction resulting in: 1) under delivery of Instructed Imbalance Energy that is also equal to or greater than the Final Hour-Ahead Schedule, or 2) over delivery of Instructed Imbalance Energy that is also less than or equal to the Final Hour-Ahead Schedule constitutes tier 1 Uninstructed Imbalance Energy that shall be settled at a Resource-Specific Settlement Interval Ex Post Price as described in Part D 2.4.
- 2) Deviations from the expected Energy associated with a Dispatch Instruction resulting in: 1) over delivery of Instructed Imbalance Energy that is also greater than the Final Hour-Ahead Schedule, or 2) under delivery of Instructed Imbalance Energy that is also less than the Final Hour-Ahead Schedule constitutes tier 2 Uninstructed Imbalance Energy and shall be settled at the Zonal Settlement Interval Ex Post Price as described in Part D 2.5.

Imbalance Energy is calculated as follows:

Generator Calculation for ISO Metered Entities:

$$IE_{i,h,o} = ME_{i,h,o} - SE_{i,h,o}$$

Load Calculation:

$$IE_{i,h,o} = SE_{i,h,o} - ME_{i,h,o}$$

System Resource Calculation:

$$IE_{i,h,o} = \sum_I^k \sum_V^y REAL_TIME_FLOW_{i,h,o,k,y} - SE_{i,h,o}$$

where,

$$SE_{i,h,o} = \frac{Hafin_{i,h}}{6}$$

$ME_{i,h,o}$ actual Meter Data for each resource i of each Settlement Interval o for each hour h .

Uninstructed Imbalance Energy is calculated as follows:

$$UIE_{i,h,o} = E_{i,h,o} - IIE_REG_{i,h,o}$$

where:

$$\begin{aligned} E_{i,h,o} = & IE_{i,h,o} - \sum_1^k IIE_LOSS_{i,h,o,k} - \sum_1^k IIE_ML_{i,h,o,k} - \\ & \sum_1^k \sum_1^m IIE_PREDISPATCH_{i,h,o,k,m} - \sum_1^k RE_STANDARD_{i,h,o,k} - \sum_1^k RED_{i,h,o,k} \\ & - \sum_1^k \sum_1^m IIE_ECON_{i,h,o,k,m} - \sum_1^k \sum_1^L OOS_P_{i,h,o,k,L} - \sum_1^k \sum_1^L OOS_N_{i,h,o,k,L} - \sum_1^k \sum_1^m RIE_{i,h,o,k,m} \\ & - \sum_1^k IIE_RERATE_{i,h,o,k} \end{aligned}$$

$IIE_REG_{i,h,o}$ is the Regulating Energy for resource i during Settlement Interval o in hour h

$$UIE_{1,i,h,o} = \begin{cases} \min \left(UIE_{i,h,o}, - \min \left(0, \sum_{1}^k \sum_{1}^m IIE_ECON_{i,h,o,k,m} + \sum_{1}^k \sum_{1}^m IIE_PREDISPATCH_{i,h,o,k,m} \right. \right. \\ \left. \left. + \sum_{1}^k \sum_{1}^L OOS_P_{i,h,o,k,L} + \sum_{1}^k \sum_{1}^L OOS_N_{i,h,o,k,L} + \sum_{1}^k RED_{i,h,o,k} \right) \right) & \therefore UIE_{i,h,o} \geq 0 \\ \left. + \sum_{1}^k IIE_LOSS_{i,h,o,k} + \sum_{1}^k \sum_{1}^m RIE_{i,h,o,k,m} + \sum_{1}^k IIE_ML_{i,h,o,k} + \sum_{1}^k RERATE_{i,h,o,k} \right) \\ \max \left(UIE_{i,h,o}, - \max \left(0, \sum_{1}^k \sum_{1}^m IIE_ECON_{i,h,o,k,m} + \sum_{1}^k \sum_{1}^m IIE_PREDISPATCH_{i,h,o,k,m} \right. \right. \\ \left. \left. + \sum_{1}^k \sum_{1}^L OOS_P_{i,h,o,k,L} + \sum_{1}^k \sum_{1}^L OOS_N_{i,h,o,k,L} + \sum_{1}^k RED_{i,h,o,k} \right) \right) & \therefore UIE_{i,h,o} < 0 \\ \left. + \sum_{1}^k IIE_LOSS_{i,h,o,k} + \sum_{1}^k \sum_{1}^m RIE_{i,h,o,k,m} + \sum_{1}^k IIE_ML_{i,h,o,k} + \sum_{1}^k RERATE_{i,h,o,k} \right) \end{cases}$$

$$UIE_{2,i,h,o} = UIE_{i,h,o} - UIE_{1,i,h,o}$$

$$UIEC_{i,h,o} = \left(-1 * UIE_{1,i,h,o} * STLMT_PRICE_{i,h,o} \right) + \left(-1 * UIE_{2,i,h,o} * ZONAL_EX_POST_PRICE_{j,h,o} \right)$$

D 2.1.2 Instructed Imbalance Energy Charges on Scheduling Coordinators

Standard Ramping Energy is Energy associated with a Standard Ramp and shall be deemed delivered and settled at a price of zero dollars per MWh.

Ramping Energy Deviation is Energy produced or consumed due to hourly schedule changes in excess of Standard Ramping Energy and shall be paid or charged, as the case may be, at a Resource-Specific Settlement Interval Ex Post Price calculated using the applicable Dispatch Interval Ex Post Prices as described in this Part D 2.4. For Scheduling Coordinators scheduling a MSS that has elected to follow its Load, this Ramping Energy Deviation will account for the units following Load.

Ramping Energy Deviation shall be settled as an explicit component of Instructed Imbalance Energy for each resource i in Dispatch Interval k of Settlement Interval o for hour h , and calculated as follows:

$$REDC_{i,h,o} = \left(\sum_{1}^k RED_{i,h,o,k} \right) * STLMT_PRICE_{i,h,o}$$

Hourly Predispatched energy from System Resources is an explicit component of Instructed Imbalance Energy for each interchange resource i in Dispatch Interval k of Settlement Interval o for hour h , and settled pursuant to Sections 11.2.4.1.1 and 11.2.4.1.1.2 of the ISO Tariff. The settlement calculation is as follows:

If (

$$(COST_AT_STLMT_PRICE_{i,h,o} \geq 0$$

And

$$BID_COST_{i,h,o} \geq 0)$$

Then

$$IIEC_PREDISPATCH_{i,h,o} = (-1) *$$

$$\left[\min(COST_AT_STLMT_PRICE_{i,h,o}, BID_COST_{i,h,o}) \right.$$

$$\left. + (STLMT_PRICE_{i,h,o} * PRE_DISP_ABC_BQ_{i,h,o}) \right]$$

Else

$$IIEC_PREDISPATCH_{i,h,o} = (-1) *$$

$$[BID_COST_{i,h,o} + (STLMT_PRICE_{i,h,o} * PRE_DISP_ABC_BQ_{i,h,o})]$$

Where

$$COST_AT_STLMT_PRICE_{i,h,o} =$$

$$\left(\sum_1^k IIE_PREDISPATCH_{i,h,o,k} \right) * STLMT_PRICE_{i,h,o}$$

$$BID_COST_{i,h,o} =$$

$\sum_1^k \sum_1^m IIE_PREDISPATCH_FOR_SEGMENT_{i,h,o,k,m} * IIE_PRICE_{i,h,o,k,m}$ for the portion of incremental energy bid segments with $IIE_PRICE_{i,h,o,k,m}$ less than or equal to the Maximum Bid Level and all decremental energy bid segments with $IIE_PRICE_{i,h,o,k,m}$ limited to the Bid Floor when $IIE_PRICE_{i,h,o,k,m}$ is less than the Bid Floor.

))

where

$PRE_DISP_ABC_BQ_{i,h,o} = \sum_1^k \sum_1^m IIE_PREDISPATCH_FOR_SEGMENT_{i,h,o,k,m}$ for the portion of incremental energy bid segments with $IIE_PRICE_{i,h,o,k,m}$ greater than the Maximum Bid Level.

The amount of Instructed Imbalance Energy that will be deemed delivered in each Dispatch Interval will be based on Dispatch Instructions, as provided for in Section 34.3, and Final Hour-Ahead Schedules. The amount of Instructed Imbalance Energy to be settled in a Settlement Interval will be equal to the sum of all Instructed Imbalance Energy for all Dispatch Intervals within the relevant Settlement Interval. Instructed Imbalance Energy for each Settlement Interval shall be settled at the relevant Resource Specific Settlement Interval Ex Post Price. Generating Units, Participating Loads, and System Units may be eligible to recover their Energy Bid costs in accordance with Section 11.2.4.1.1.1. Instructed Imbalance Energy from System Resources shall be settled in accordance with Section 11.2.4.1.1.2.

The Instructed Imbalance Energy amount for each resource i in Settlement Interval o for hour h shall be determined as follows:

$$IIEC_{i,h,o} = (-1) * \left(\sum_{k=1}^k \sum_{m=1}^m IIE_ECON_{i,h,o,k,m} + \sum_{k=1}^k \sum_{m=1}^m RIE_{i,h,o,k,m} \right) * STLMT_PRICE_{i,h,o} \\ + \sum_{k=1}^k IIE_RERATE_{i,h,o,k} + \sum_{k=1}^k IIE_ML_{i,h,o,k} \\ + IIEC_OOS_{i,h,o} + REDC_{i,h,o} + IIEC_REG_{i,h,o} + IIEC_PREDISPATC H_{i,h,o}$$

Uninstructed Imbalance Energy is Imbalance Energy due to non-compliance with a Dispatch Instruction and shall be settled as provided for in SABP Part D Section 2.1.1.

D 2.2 Unaccounted for Energy Charge

The Unaccounted for Energy Charge on Scheduling Coordinator g in Settlement Interval o of Settlement Period h for each relevant Zone j is calculated in the following manner:

The UFE for each utility Service Area s , for which separate UFE calculation is performed, is calculated as follows,

$$UFE_{UDC,s,h,o} = \sum_{q \in UDC_s} I_{a,q,j,h,o} - \sum_{q \in UDC_s} E_{a,q,j,h,o} + \sum_{i \in UDC_s} G_{a,i,j,h,o} - \sum_{i \in UDC_s} L_{a,i,j,h,o} - TL_{s,h,o}$$

The Transmission Loss $TL_{s,h,o}$ in Settlement Interval o of Settlement Period h for utility Service Area s is calculated as follows:

$$TL_{s,h,o} = \left(\sum_i [G_{a,i,j,h,o} * (1 - GMM_{a,i,h})] + \sum_q [I_{a,q,j,h,o} * (1 - GMM_{a,q,h})] \right) * \frac{PFL_{s,h}}{\sum_s PFL_{s,h}} \text{ Where}$$

$PFL_{s,h}$ are the Transmission Losses for utility Service Area s as calculated by a power flow solution for Settlement Period h , consistent with the calculation of final forecasted Generation Meter Multipliers.

Each metered demand point z in utility Service Area s , either ISO grid connected or connected through UDC s , is allocated a portion of the UFE as follows:

$$UFE_{i,j,h,o} = UFE_{UDC,s,h,o} * \frac{L_{i,j,h,o}}{\sum_{i \in UDC_s} L_{i,j,h,o}}$$

The UFE charge for Scheduling Coordinator g for Settlement Interval o of Settlement Period h in Zone j is calculated as a charge or payment using the applicable Zonal Settlement Interval Ex Post Price as follows:

$$UFEC_{g,j,h,o} = \left(\sum_{i \in SCg} UFE_{i,j,h,o} \right) * ZONAL_EX_POST_PRICE_{j,h,o}$$

D 2.3 Hourly Ex Post Price

The Hourly Ex Post Price is the Energy-weighted average of the Dispatch Interval Ex Post Prices in each Zone j during each Settlement Period using the absolute value of Instructed Imbalance Energy procured from all Participating Generators, Participating Load, System Units, and System Resources in each applicable Dispatch Interval. The Hourly Ex Post Price may vary between Zones if Congestion is present.

$$HP_{j,h} = \frac{\sum_{l=1}^p \sum_{i=1}^i |IIE_TOTAL_{j,i,h,p}| * EX_POST_PRICE_{j,h,o,p}}{\sum_{l=1}^p \sum_{i=1}^i |IIE_TOTAL_{j,i,h,p}|}$$

where,

p is the Dispatch Interval index for hour h .

D 2.4 Resource-Specific Settlement Interval Ex Post Price

The Resource-Specific Settlement Interval Ex Post Price is the weighted-average of the Dispatch Interval Ex Post Prices in each Settlement Interval using the Instructed Imbalance Energy from the respective Participating Generator, Participating Load, or System Resource, in each applicable Dispatch Interval. If there is no Instructed Imbalance Energy from a Participating Generator, Participating Load, or System Resource, in any of the applicable Dispatch Intervals, the Resource-Specific Settlement Interval Ex Post Price for that resource would be the simple average of the applicable Dispatch Interval Ex Post Prices in the Settlement Interval.

The Resource-Specific Settlement Interval Ex Post Price is calculated as follows:

$$STLMT_PRICE_{i,h,o} = \frac{\sum_{k=1}^k IIE_TOTAL_{i,h,o,k} * EX_POST_PRICE_{j,h,o,k}}{\sum_{k=1}^k IIE_TOTAL_{i,h,o,k}}$$

Where:

$$\begin{aligned}
 IIE_TOTAL_{i,h,o,k} = & \\
 & \sum_1^m IIE_ECON_{i,h,o,k,m} + \sum_1^m IIE_PREDISPATCH_{i,h,o,k,m} + \\
 & IIE_ML_{i,h,o,k} + \sum_1^m RIE_{i,h,o,k,m} + \sum_1^L OOS_P_{i,h,o,k,L} + \\
 & \sum_1^L OOS_N_{i,h,o,k,L} + IIE_LOSS_{i,h,o,k} + RED_{i,h,o,k} + \sum_1^k IIE_RERATE_{i,h,o,k}
 \end{aligned}$$

D 2.5 Zonal Settlement Interval Ex Post Price

The Zonal Settlement Interval Ex Post Price is the weighted-average of the Dispatch Interval Ex Post Prices in each Settlement Interval using the absolute value of Instructed Imbalance Energy procured from all Participating Generators, Participating Load, System Units, and System Resources in each applicable Dispatch Interval. If there is no Instructed Imbalance Energy from a Participating Generator, Participating Load, or System Resource, in any of the applicable Dispatch Intervals, the Zonal Settlement Interval Ex Post Price for that Zone would be the simple average of the applicable Dispatch Interval Ex Post Prices in the Settlement Interval.

The Zonal Settlement Interval Ex Post Price is calculated as follows:

$$\begin{aligned}
 ZONAL_EX_POST_PRICE_{j,h,o} = & \\
 & \frac{\sum_{p=1}^2 \sum_1^i |IIE_TOTAL_{i,h,p}| * EX_POST_PRICE_{j,h,o,p}}{\sum_{p=1}^2 \sum_1^i |IIE_TOTAL_{i,h,p}|}
 \end{aligned}$$

where p is the Dispatch Interval index for hour h.

D 2.6 Calculation of Unrecovered Cost Payment for Generating Units, System Units, Dynamically Scheduled System Resources, and Curtailable Demand.

As set forth in 11.2.4.1.1.1, Generating Units, System Units, dynamically scheduled System Resources, and Curtailable Demand resources will be eligible to recover their bid costs (less than or equal to the Maximum Bid Level) for extra-marginal Energy dispatched above Pmin, if such costs are not recovered from the net of expected revenues earned through participation in the ISO's Real Time Market during the Trade Day (24-hour period).

The Unrecovered Cost Payment for each resource i shall be determined for the Trade Day d then evenly divided over n-Settlement Intervals as follows:

$$COST_RECOVERY_{i,d} = \min(0, \sum_1^h \sum_1^o (MR_DEFICIT_{i,h,o} + MR_SURPLUS_{i,h,o}))$$

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:

$$TOLERANCE_BAND_{i,h,o} = \pm \max(FIX_LIM, TOL_PERCENT * P_{\max_i}) / 6$$

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%. P_{\max_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:

$$TOLERANCE_BAND_{i,h,o} = \pm \max(FIX_LIM, TOL_PERCENT * HAFin_{i,h}) / 6$$

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:

$$URC_ALLOC_{g,h,o} = M_{g,h,o} * Per\ Unit\ Price$$

where,

$M_{g,h,o}$ = the Metered Demand in the ISO control area for Scheduling

Coordinator g in Settlement Interval o for hour h ;

$$Per\ Unit\ Price = \frac{-1 * \sum_1^i COST_RECOVERY_{i,h,o}}{\sum_1^g M_{g,h,o}}$$

D 2.6.3 Calculation of Unrecovered Bid Cost Payment for System Resources

As set forward in Section 11.2.4.1.1.2, System Resources that are pre-dispatched hourly incremental or decremental Instructed Imbalance Energy will be settled based on their Energy bid costs for each Settlement Interval for the quantity of Energy delivered in each Settlement Interval. The hourly pre-dispatched Instructed Imbalance Energy is first settled as set forth in Section D 2.1.2. An additional uplift payment for any applicable Settlement Interval shall be determined when settlement as set forth in Section D 2.1.2 is insufficient recovery of its bid costs for the Settlement Interval. For pre-dispatched hourly Instructed Imbalance Energy, where the resource-specific settlement amount is positive and the bid-cost is positive, an uplift payment is determined for each Settlement Interval based on the minimum of zero or the difference between the resource-specific settlement amount and the bid cost settlement amount as follows:

The predispached uplift payment for each applicable Settlement Interval is calculated as follows:

$$PREDISPATCH_PMT_{i,h,o} = PREDISPATCH_UPLIFT_{i,h} / n$$

If (

$$(COST_AT_STLMT_PRICE_{i,h,o} >= 0$$

And

$$BID_COST_{i,h,o} >= 0)$$

Then

$$PREDISPATCH_UPLIFT_{i,h,o} = \min(0, COST_AT_STLMT_PRICE_{i,h,o} - BID_COST_{i,h,o})$$

Where

$$COST_AT_STLMT_PRICE_{i,h,o} =$$

$$\left(\sum_{1}^k IIE_PREDISPATCH_{i,h,o,k} \right) * STLMT_PRICE_{i,h,o}$$

$$BID_COST_{i,h,o} =$$

$$\sum_{1}^k \sum_{1}^m IIE_PREDISPATCH_FOR_SEGMENT_{i,h,o,k,m} * IIE_PRICE_{i,h,o,k,m}$$

Else

$$PREDISPATCH_UPLIFT_{i,h,o} = 0$$

for the portion of incremental energy bid segments with IIE PRICE_{i,h,o,k,m} less than or equal to the Maximum Bid Level and all decremental energy bid segments with IIE PRICE_{i,h,o,k,m} limited to the Bid Floor when IIE PRICE_{i,h,o,k,m} is less than the Bid Floor.

D 2.6.4 Allocation of Unrecovered Cost Payments for Hourly Pre-dispatched System Resources

For each Settlement Interval o, the total uplift payments (*PREDISPATCH_PMT_{i,h,o}*) for all hourly pre-dispatched System Resources will be included in the Excess Cost Payments to be allocated to a Scheduling Coordinator's Net Negative Deviation through allocation of excess costs and/or ISO metered Demand through excess cost neutrality allocation.

D 2.6.5 Excess Cost Payments for Instructed Incremental Energy Bids above the Maximum Bid Level

Incremental Instructed Imbalance Energy above the Maximum Bid Level will receive an additional Excess Cost Payment subject to operating within a resource's Tolerance Band.

Excess cost payments are calculated as follows:

$$EXCESS_COST_{i,h,o} = \left[\left(\sum_{1}^k \sum_{1}^m IIE_ECON_{i,h,o,k,m} + \sum_{1}^k \sum_{1}^m IIE_PREDISPATCH_{i,h,o,k,m} + \sum_{1}^k \sum_{1}^m RIE_{i,h,o,k,m} \right) * STLMT_PRICE_{i,h,o} - BID_COST_{i,h,o} - BID_COST_RIE_{i,h,o} \right] * PERF_STAT_{i,h,o}$$

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:

$$TL_{i,h,o} =$$

$$\sum_l^k \sum_l^v REAL_TIME_FLOW_{i,h,o,k,v} * (1 - GMMa_h)$$

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]

D 3.7 **$G_{a,i,j,h,o}$ – MWh**

The total actual metered Generation of Generator i in Zone j during Settlement Interval o during Settlement Period h.

D 3.8 **[Not Used]**

D 3.9 **[Not Used]**

D 3.9.1 **[Not Used]**

D 3.10 **[Not Used]**

D 3.11 **[Not Used]**

D 3.12 **$GMM_{a,i,h}$ – fraction**

The final forecasted Generation Meter Multiplier (GMM) for a Generator i in Settlement Period h as calculated by the ISO at the hour-ahead stage (but after close of the Hour-Ahead Market).

D 3.13 **$GMM_{a,j,h}$ – fraction**

The forecasted Generation Meter Multiplier for an Energy import at Scheduling Point q in Settlement period h as provided to the Scheduling Coordinator by the ISO after close of the Hour-Ahead Market.

D 3.14 **[Not Used]**

D 3.15 **$L_{a,i,j,h,o}$ – MWh**

The actual metered Demand of Demand i in Zone j in Settlement Interval o during Settlement Period h.

D 3.15.1 **[Not Used]**

D 3.15.2 **[Not Used]**

D 3.16 **[Not Used]**

D 3.17 **[Not Used]**

D 3.17.1 **[Not Used]**

D 3.18 **[Not Used]**

D 3.19 **$I_{a,q,j,h,o}$ – MWh**

The total actual Energy import of Scheduling Coordinator g through Scheduling Point q in Settlement Interval o during Settlement Period h. This is deemed to be equal to the scheduled Energy over the same interval.

D 3.20 **[Not Used]**

D 3.21 [Not Used]

D 3.22 [Not Used]

D 3.23 $E_{a,q,j,h,o}$ – MWh

The total actual Energy export of Scheduling Coordinator g through Scheduling Point q in Settlement Interval o for Settlement Period h . This is deemed to be equal to the total scheduled Energy export during the same interval.

D 3.24 [Not Used]

D 3.25 [Not Used]

D 3.25.1 [Not Used]

D 3.26 $UFEC_{jxt}$ – \$

The Unaccounted for Energy Charge for Scheduling Coordinator j in Zone x in Settlement Period t . It is the cost for the Energy difference between the net Energy delivered into each utility Service Area, adjusted for utility Service Area Transmission Losses (calculated in accordance with ISO Tariff Section 27.2.1.), and the total metered Demand within that utility Service Area adjusted for distribution losses using Distribution System loss factors approved by the Local Regulatory Authority.

This Energy difference (UFE) is attributed to meter measurement errors, power flow modeling errors, energy theft, statistical Load profile errors, and distribution loss deviations.

D 3.27 $UFE_{UDC,bkt}$ – MWh

The Unaccounted for Energy (UFE) for utility Service Area k .

D 3.28 UFE – MWh

The portion of Unaccounted for Energy (UFE) allocated to metering point z .

D 3.29 [Not Used]

D 3.30 [Not Used]

D 3.31 [Not Used]

D 3.32 [Not Used]

D 3.33 [Not Used]

D 3.34 [Not Used]

D 3.35 [Not Used]

D 3.36 [Not Used]

D 3.37 **TLs,h,o – MWh**

The Transmission Losses per Settlement Interval o in Settlement Period hour h in utility Service Area s .

D 3.38 **[Not Used]**

D 3.39 **[Not Used]**

D 3.40 **[Not Used]**

D 3.41 **[Not Used]**

D 3.42 **[Not Used]**

D 3.43 **[Not Used]**

D 3.44 **[Not Used]**

D 3.45 **[Not Used]**

D 3.46 **[Not Used]**

D 3.47 **[Not Used]**

D 3.48 **[Not Used]**

D 3.49 **EX_POST_PRICE_{j,h,o,k} – \$/MWh**

The Ex-Post Price in Dispatch Interval k of Settlement Interval o in Settlement Period h in Zone j .

D 3.50 **HRLY_EX_POST_PRICE_{j,h} – \$/MWh**

The energy-weighted Ex Post Price for Settlement Period h in Zone j .

D 3.51 **STLMT_PRICE_{i,h,o} – \$/MWh**

The 10-minute Settlement price (Resource-Specific Settlement Interval Ex Post Price) for resource i in the Settlement Interval o for the Settlement Period h .

D 3.52 **SE_{i,h,o} – MWh**

The Scheduled Energy from resource i during Settlement Interval o of Settlement Period h .

D 3.53 **TOLERANCE_BAND_{i,h,o} – MWh**

The Tolerance Band limit for resource i during Settlement Interval o of Settlement Period h .

D 3.54 **IIE_ECON_{i,h,o,k,m} – MWh**

The dispatched incremental or decremental Instructed Imbalance Energy (IIE) for resource i during Dispatch Interval k in Settlement Interval o of Settlement Period h for bid segment m .

Decremental Energy shall be represented as a negative quantity.

IIE_ECON_{i,h,o,k,m} shall be comprised of any of the four *IIE_TYPE*'s: SUPP, SPIN, NSPN or RPLC and be associated with its respective *IIE_PRICE_{i,h,o,k,m}*

D 3.55 **IIE_PRICE_{i,h,o,k,m} – \$/MWh**

The bid price for energy bid segment m for resource i during Dispatch Interval k in Settlement Interval o of Settlement Period h for bid segment m

D 3.56 **IIE_PREDISPATCH_{i,h,o,k,m} – MWh**

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

D 3.57 **RIE_{i,h,o,k,m} – MWh**

The Residual Energy for resource i during Dispatch Interval k in Settlement Interval o of Settlement Period h for bid segment m .

D 3.58 **RIE_PRICE_{i,h,o,k,m} – \$/MWh**

The reference bid price for the Residual Energy for resource i during Dispatch Interval k in Settlement Interval o of Settlement Period h for bid segment m .

D 3.59 **OOS_PRICE_{i,h,o,k,L} – \$/MWh**

The Settlement price for the Instructed Out of Stack Energy for resource i during Dispatch Interval k in Settlement Interval o of Settlement Period h for index number L .

D 3.60 **IIE_REG_{i,h,o} – MWh**

The Regulating Energy for resource i during Settlement Interval o in Settlement Period h .

D 3.61 **IIE_PREDISPATCH _{i,h,p} – MWh**

The Settlement Period pre-dispatched Energy for resource i during Dispatch Interval p of Settlement Period h .

D 3.62 **E _{i,h,o} – MWh**

Calculated as the difference of $IE_{i,h,o}$ and $IIE_TOTAL_{i,h,o,k}$ and is equal to the sum of Uninstructed Imbalance Energy and Regulating Energy of resource i during Settlement Interval o in Settlement Period h .

D 3.63 **IIEC _{i,h,o} – \$**

The Instructed Imbalance Energy payment (charge) for resource i during Settlement Interval o of Settlement Period h .

D 3.64 **IIEC_OOS _{i,h,o} – \$**

The total OOS Energy payment (charge) for resource i during Settlement Interval o of Settlement Period h .

D 3.65 **IIEC_OOS_P _{i,h,o} – \$**

The incremental Instructed OOS Imbalance Energy payment (charge) for resource i during Settlement Interval o of Settlement Period h .

D 3.66 **IIEC_OOS_N _{i,h,o} – \$**

The decremental Instructed OOS Imbalance Energy payment (charge) for resource i during Settlement Interval o of Settlement Period h .

D 3.67 **IIE_LOSS _{i,h,o,k} – MWh**

The transmission loss self-provided Energy from resource i during Dispatch Interval k in Settlement Interval o of Settlement Period h .

D 3.68 **IIE_ML _{i,h,o,k} – MWh**

The Imbalance Energy due to Minimum Load from resource i during Dispatch Interval k in Settlement Interval o of Settlement Period h .

D 3.69 **IIE_TOTAL _{i,h,o,k} – MWh**

The total Instructed Imbalance Energy from all energy sources except Regulation for resource i during Dispatch Interval k in Settlement Interval o of Settlement Period h .

D 3.70 **IIE_RERATE _{i,h,o,k} – MWh**

The SLIC derated Pmin or Pmax value as a result of a Scheduling Coordinator modifying its operating output level for a given resource i during Dispatch Interval k in Settlement Interval o of Settlement Period h .

D 3.71 **UIE_{i,h,o} – MWh**

The total Uninstructed Imbalance Energy from resource i during Settlement Interval o of Settlement Period h .

D 3.72 **UIE_1_{i,h,o} – MWh**

The Uninstructed Imbalance Energy attributed to non-compliance of IIE_ECON from resource i during Settlement Interval o of Settlement Period h .

D 3.73 **UIE_2_{i,h,o} – MWh**

The Uninstructed Imbalance Energy exclusive of UIE_1 from resource i during Settlement Interval o of Settlement Period h .

D 3.74 **UIEC_{i,h,o} – \$**

The Uninstructed Imbalance Energy payment (charge) for resource i during Settlement Interval o of Settlement Period h .

D 3.75 **ZONAL_EX_POST_PRICE_{j,h,o} – \$/MWh**

The energy weighted average Ex Post Price for Imbalance Energy for Zone j in Settlement Interval o for Settlement Period h .

D 3.76 **ME_{i,h,o} – MWh**

The Metered Energy from resource i during Settlement Interval o of Settlement Period h .

D 3.77 **RED_{i,h,o,k} – MWh**

The Ramping Energy Deviation from resource i during Dispatch Interval k in Settlement Interval o of Settlement Period h .

D 3.78 **REDC_{i,h,o} – \$**

The Ramping Energy Deviation payment (charge) for resource i during Settlement Interval o of Settlement Period h .

D 3.79 **MR_ML_{i,h,o} – \$**

The expected Real Time Market revenue from Minimum Load Energy for resource i in Settlement Interval o for Settlement Period h .

D 3.80 **COST_RECOVERY_{i,d} – \$**

The Unrecovered Cost Payment for resource i for Trading Day d .

D 3.81 **MR_DIFF _{i,h,o}**

is the market revenue surplus or deficit for resource i in Settlement Period h for Settlement Interval o .

D 3.82 **MR_DEFICIT _{i,h,o} – \$**

The market revenue deficit for resource i in Settlement Period h for Settlement Interval o .

D 3.83 **MR_SURPLUS _{i,h,o} – \$**

The market revenue surplus for resource i in Settlement Period h for Settlement Interval o .

D 3.84 **PERF_STAT _{i,h,o} – True/False**

The performance status of resource i for Settlement Interval o of Settlement Period h . The performance status is equal to 1 (compliant) or 0 (non-compliant).

D 3.85 **BID_COST _{i,h,o} – \$**

The bid costs for IIE, except OOS Energy and RIE, for resource i in Settlement Period h for Settlement interval o .

D 3.86 **BID_COST_RIE _{i,h,o} – \$**

The bid costs for RIE for resource i in Settlement Period h for Settlement Interval o .

D 3.87 **PREDISPATCH_PMT _{i,h,o} – \$**

The unrecovered bid cost payment for a Settlement Period pre-dispatched System Resource i in Settlement Interval o for Settlement Period h .

D 3.88 **EXCESS_COST _{i,h,o} – \$**

The excess cost payment for resource i in Settlement Interval o for Settlement Period h .

D 3.89 **TL _{i,h,o} – MWh**

The Transmission Loss Obligation for resource i during Settlement Interval o of Settlement Period h .

D 3.90 **EXCESS_COST_ALLOC _{g,h,o} – \$**

The excess cost allocation for Scheduling Coordinator g in Settlement Period h for Settlement Interval o .

D 3.91 **REAL_TIME_FLOW_{i,h,o,k,v} – MWh**

The real-time actual flow for intertie resource *i* during Dispatch Interval *k* during Settlement Interval *o* of Settlement Period *h* for Real Time Flow Type index *v*. Real Time Flow Type index *v* must be one of the following Energy types: FIRM NFIRM, SUPP, WHEEL, DYN, ESPN, ENSPN, OOM, ERPLC.

D 3.92 **RE_STANDARD_{i,h,o,k} – MWh**

The Standard Ramping Energy from resource *i* during Dispatch Interval *k* of Settlement Interval *o* of Settlement Period *h*.

D 3.93 **OOS_P_{i,h,o,k,L} – MWh**

The incremental Out of Stack Energy for resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h* for index number *L*.

D 3.94 **OOS_N_{i,h,o,k,L} – MWh**

The decremental Out of Stack Energy for resource *i* during Dispatch Interval *k* in Settlement Interval *o* of Settlement Period *h* for index number *L*.

D 3.95 **URC_ALLOC_{g,h,o} – \$**

The unrecovered cost neutrality allocation for Scheduling Coordinator *g* in Settlement Interval *o* for Settlement Period *h*.

D 3.96 **IIE_TYPE_{i,h,o,k,m}**

is the energy type for *IIE_ECON_{i,h,o,k,m}*. Energy type is one of the following: Supplemental, Spin, Non-Spin or Replacement Reserve Energy.

PART E

USAGE CHARGE COMPUTATION

E 1 Purpose of Charge

The Usage Charge is payable by Scheduling Coordinators who schedule Energy across Congested Inter-Zonal Interfaces pursuant to Section 27.1.1.5 of the ISO Tariff. Scheduling Coordinators who counter-schedule across Congested Inter-Zonal Interfaces are entitled to Usage Charge Payments. The right to schedule across a Congested Inter-Zonal Interface is determined through the ISO's Congestion Management procedures.

The following categories of Payments and Charges are covered in this Part E:

- (a) Usage Charges payable by Scheduling Coordinators for Energy transfers scheduled across Congested Inter-Zonal Interfaces and which contribute to Congestion.
- (b) Usage Charge rebates payable to Scheduling Coordinators for Energy transfers scheduled across Congested Inter-Zonal Interfaces and which contribute to relieving Congestion.
- (c) Credits of net Usage Charge revenues to Participating TOs and FTR Holders.
- (d) Debits of net Usage Charge revenues to Participating TOs and FTR Holders.
- (e) Debits and rebates of Usage Charge to Scheduling Coordinators as set out in E 2.3.3.

E 2 Fundamental Formulae

E 2.1 ISO Usage Charges on Scheduling Coordinators

Each Scheduling Coordinator j whose Final Schedule includes the transfer of Energy scheduled across one or more Congested Inter-Zonal Interfaces shall (save to the extent that the transfer involves the use of transmission capacity represented by Existing Rights) pay, or be paid, Usage Charges in Trading Interval t calculated in accordance with the following formulae:

In the Day-Ahead Market:

$$UC_{jtd} = \sum_x NetZoneImp_{jtxd} * \lambda_{dxt}$$

In the Hour-Ahead Market:

$$UC_{jth} = \sum_x (NetZoneImp_{jtxh} - NetZoneImp_{jtxd}) * \lambda_{hxt}$$

E 2.2 Payments of Usage Charges to Scheduling Coordinators

Each Scheduling Coordinator j whose Final Schedule includes the transfer of Energy from one Zone to another in a direction opposite that of Congestion shall (save to the extent that the transfer involves the use of transmission capacity represented by Existing Rights) receive a Usage Charge payment from the ISO calculated in accordance with the formulae described in Section E 2.1.

E 2.3 ISO Credits and Debits to Transmission Owners and FTR Holders of Usage Charge Revenues

E 2.3.1 Day-Ahead Market

The ISO will pay to the Participating TO n and FTR Holder n its share of the total net Usage Charge revenue for Trading Interval t in the Day-Ahead Market in accordance with the following formula:

$$PayUC_{ntd} = \sum_y \mu_{ytd} * K_{yn} * L_{ytd}$$

E 2.3.2 Hour-Ahead Market

The ISO will pay to the Participating TO n and FTR Holder n its share of the total net Usage Charge revenue for Trading Interval t in the Hour-Ahead Market in accordance with the following formula:

$$PayUC_{nth} = \sum_y \mu_{yth} * K_{yn} * (L_{yth} - L_{ytd})$$

Under normal operating conditions, $(L_{yth} - L_{ytd})$ is positive and Participating TOs and FTR Holders will receive a refund on the net Usage Charge for the relevant Trading Interval t in the Hour-Ahead Market.

E 2.3.3 Debits to Participating TOs and FTR Holders and Debits/Rebates to Scheduling Coordinators

If, after the close of the Day-Ahead Market, Participating TOs instruct the ISO to reduce interface limits based on operating conditions or an unscheduled transmission Outage occurs and as a result of either of those events, Congestion is increased and Available Transfer Capacity is decreased in the Inter-Zonal Interface in the Hour-Ahead Market, the $(L_{yth} - L_{ytd})$ will be negative. In this case:

- (a) Participating TOs and FTR Holders will be charged for the Usage Charge payments they received for the relevant Trading Interval t in the Day-Ahead Market with respect to the reduced interface limits;
- (b) Any Scheduling Coordinator whose Schedule was adjusted for the relevant Trading Interval t in the Hour-Ahead Market due to the reduced interface limits will be credited with μ_{yth} for each MW of the adjustment; and

- (c) Each Scheduling Coordinator will be charged an amount equal to its proportionate share, based on Schedules in the Day-Ahead Market in the direction of Congestion, of the difference between $\mu_{yth}(Ly_{th} - Ly_{td})$ and the total amount charged to Participating TOs and FTR Holders in accordance with item (a) above.

The ISO will issue a notice to Scheduling Coordinators of the operating hour, and extent, for which the derate will apply in the relevant Hour-Ahead Markets. The timing and form of such notices shall be set forth in ISO procedures.

E 3 Meaning of terms of formulae

E 3.1 UC_{jtd} (\$)

The Usage Charge payable by or to Scheduling Coordinator j for the relevant Trading Interval t in the Day-Ahead Market.

E 3.2 UC_{jth} - \$

The Usage Charge payable by or to Scheduling Coordinator j for Trading Interval t in the Hour-Ahead Market.

E 3.3 $NetZonalImp_{jtxd}$ (MWh)

The net Zonal import scheduled by Scheduling Coordinator j in Zone x for the relevant Trading Interval t in the Day-Ahead Market. For Zones internal to the ISO Control Area, net Zonal import equals scheduled Demand minus scheduled Generation plus transfers. For zones external to the ISO Control Area (i.e., for Scheduling Points), net zonal import equals scheduled imports (i.e., out of the ISO Control Area) minus scheduled exports (i.e., into the ISO Control Area).

E 3.4 $NetZonalImp_{jtxh}$ (MWh)

The net Zonal import scheduled by the Scheduling Coordinator j in Zone x for the relevant Trading Interval t in the Hour-Ahead Market. For Zones internal to the ISO Control Area, net Zonal import equals scheduled Demand minus scheduled Generation plus transfers. For Zones external to the ISO Control Area (i.e., for Scheduling Points), net zonal import equals scheduled imports (i.e., out of the ISO Control Area) minus scheduled exports (i.e., into the ISO Control Area).

E 3.5 λ_{dxt} (\$/MWh)

The reference Zonal marginal price for Zone x for the relevant Trading Interval t in the Day-Ahead Market, as calculated by the ISO's Congestion Management computer optimization algorithm.

E 3.6 λ_{hxt} (\$/MWh)

The reference Zonal marginal price for Zone x for the relevant Trading Interval t in the Hour-Ahead Market, as calculated by the ISO's Congestion Management computer optimization algorithm.

E 3.7 $PayUC_{ntd}$ (\$)

The amount calculated by the ISO to be paid to or by the Participating TO n (in respect of its Transmission Revenue Balancing Account) and FTR Holder n for the relevant Trading Interval t in the Day-Ahead Market.

E 3.7.1 PayUC_{nth} (\$)

The amount calculated by the ISO to be paid to the Participating TO n (in respect of its Transmission Revenue Balancing Account) and FTR Holder n for the relevant Trading Interval t in the Hour-Ahead Market.

E 3.8 μ_{ytd} (\$/MW)

The Day-Ahead Congestion price (shadow price) at Inter-Zonal Interface y for Trading Interval t. This price is calculated by the ISO's Congestion Management computer optimization algorithm.

E 3.8.1 μ_{yth} (\$/MW)

The Hour-Ahead Congestion price (shadow price) at Inter-Zonal Interface y for Trading Interval t. This price is calculated by the ISO's Congestion Management computer optimization algorithm.

E 3.9 Kytn (%)

The percentage of the Inter-Zonal Congestion revenue allocation for Participating TO n and FTR Holder n of the Congested Inter-Zonal interface y for the relevant Trading Interval t for both Day-Ahead and Hour-Ahead Markets.

E 3.10 Lytd (MW)

The total loading of Inter-Zonal Interface y for Trading Interval t in the Day-Ahead as calculated by the ISO's Congestion Management optimization algorithm.

E 3.11 Lyth (MW)

The total loading of Inter-Zonal Interface y for Trading Interval t in the Hour-Ahead as calculated by the ISO's Congestion Management optimization algorithm.

PART F

WHEELING ACCESS CHARGES COMPUTATION

F 1 Purpose of Charge

The Wheeling Access Charge is paid by Scheduling Coordinators for Wheeling as set forth in Section 26.1.4 of the ISO Tariff. The ISO will collect the Wheeling revenues from Scheduling Coordinators on a Trading Interval basis and repay these to the Participating TOs based on the ratio of each Participating TO's Transmission Revenue Requirement to the sum of all Participating TOs' Revenue Requirements.

F 2 Fundamental Formulae

F 2.1 ISO Charges on Scheduling Coordinators for Wheeling

The ISO will charge Scheduling Coordinators scheduling a Wheeling Out or a Wheeling Through, the product of the Wheeling Access Charge and the total of the hourly schedules of Wheeling in MWh for each Trading Interval at each Scheduling Point associated with that transaction pursuant to Section 26.1.4 of the ISO Tariff.

F 2.1.1 Wheeling Access Charge

The Wheeling Access Charge for each Participating TO shall be as specified in Section 26.1.4 of the ISO Tariff.

F 2.1.2 [Not Used]

F 2.2 ISO Payments to Transmission Owners for Wheeling

The ISO will pay all Wheeling revenues to Participating TOs on the basis of the ratio of each Participating TO's Transmission Revenue Requirement ("TRR") (less the TRR associated with Existing Rights) to the sum of all Participating TOs' TRRs (less the TRRs associated with Existing Rights) as specified in Section 26.1.4.3 of the ISO Tariff. The Low Voltage Wheeling Access Charge shall be disbursed to the appropriate Participating TO. The sum to be paid to Participating TO_n for a Trading Interval is calculated as follows:

$$PayTO_n = \frac{TRR_n}{\sum_n TRR_n} * \sum_j totalWChrg_j$$

F 3 Meaning of terms in formulae

F 3.1 WABC_q (\$/kWh)

The Weighted Average Rate for Wheeling Service for Scheduling Point q.

F 3.2 **P_n** **(\$/kWh)**

The applicable Wheeling Access Charge rate for TAC Area or Participating TO n in \$/kWh as set forth in Section 26.1.4 of the ISO Tariff and Section 4.6 of the TO Tariff.

F 3.3 **Q_n** **(MW)**

The Available Transfer Capacity, whether from transmission ownership or contractual entitlements, of each Participating TO n for each ISO Scheduling Point which has been placed within the ISO Controlled Grid. Available Transfer Capacity does not include capacity associated with Existing Rights of a Participating TO as defined in Section 16.2 of the ISO Tariff.

F 3.4 **$WChg_{jq}$** **(\$)**

The Wheeling Charges by the ISO on Scheduling Coordinator j for Scheduling Point q in Trading Interval t. Both Wheeling Out and Wheeling Through transactions are included in this term.

F 3.5 **$QChargeW_{jq,t}$** **(kWh)**

The summation of kWh wheeled over Scheduling Point q by Scheduling Coordinator j in Trading Interval t. Both Wheeling Out and Wheeling Through transactions are included in this term.

PART G

**VOLTAGE SUPPORT and BLACK START
CHARGES COMPUTATION**

G 1 Purpose of charge

G 1.1 Voltage Support (VS) and Black Start (BS) charges are the charges made by the ISO to recover costs it incurs under contracts entered into between the ISO and those entities offering to provide VS or BS. Each Scheduling Coordinator pays an allocated proportion of the VS&BS charge to the ISO so that the ISO recovers the total costs incurred.

G 1.2 All Generating Units are required by the ISO Tariff to provide reactive power by operating within a power factor range of 0.90 lag and 0.95 lead. Additional short-term Voltage Support required by the ISO is referred to as supplemental reactive power. If the ISO requires the delivery of this supplemental reactive power by instructing a Generating Unit to operate outside its mandatory MVar range, the Scheduling Coordinator representing this Generating Unit will only receive compensation if it is necessary to reduce the MW output to achieve the MVar instructed output. Supplemental reactive power charges to Scheduling Coordinators are made on a Trading Interval basis. As of the ISO Operations Date the ISO will contract for long-term Voltage Support Service with the Owner of Reliability Must-Run Units under Reliability Must-Run Contracts.

G 1.3 The ISO will procure Black Start capability through contracts let on an annual basis. The quantities and locations of the Black Start capability will be determined by the ISO based on system analysis studies. Charges to Scheduling Coordinators for instructed Energy output from Black Start units are made on a Trading Interval basis.

G 2 Fundamental formulae

G 2.1 Payments to Scheduling Coordinators for providing Voltage Support

Payments to Scheduling Coordinators for additional Voltage Support service comprise:

G 2.1.1 Lost Opportunity Cost Payments (supplemental reactive power) to Scheduling Coordinators for Generating Units

When the ISO obtains additional Voltage Support by instructing a Generating Unit to operate outside its mandatory MVar range by reducing its MW output the ISO will select Generating Units based on their Supplemental Energy Bids (\$/MWh). Subject to any locational requirements the ISO will select the Generating Unit with the highest decremental Supplemental Energy Bid to reduce MW output by such amount as is necessary to achieve the instructed MVar reactive energy production. Each Trading Interval the ISO will pay Scheduling Coordinator j for that Generating Unit i in Zone x, the lost opportunity cost (\$) resulting from the reduction of MW output in Trading Interval t in accordance with the following formula:

$$VSS_{xijt} = \text{Max} \{0, P_{xt} - \text{Sup}_{xdecit}\} * DEC_{xit}$$

G 2.1.2 Long-term contract payments to Scheduling Coordinators for Reliability Must-Run Units for Generating Units and other Voltage Support Equipment

The ISO will pay Scheduling Coordinator j for the provision of Voltage Support from its Reliability Must-Run Units located in Zone x in month m a sum ($VSLT_{xjm}$) consisting of:

- (a) the total of the Ancillary Service Pre-empted Dispatch Payments if the ISO has decreased the output of the Reliability Must-Run Units for the provision of Voltage Support outside the power factor range of the Reliability Must-Run Unit in any Trading Interval in month m and/or
- (b) (if applicable) the total payments for the provision of Voltage Support in month m requested by the ISO from the synchronous condensers of the Reliability Must-Run Units,

calculated in each case in accordance with the terms of the relevant Reliability Must-Run Contract. Data on these payments will not be generated by the ISO. Such data will be based on the invoices issued by the Owners of Reliability Must-Run Generating Units pursuant to their Reliability Must-Run Contracts and will be verified by the ISO.

G 2.2 Charges to Scheduling Coordinators for Voltage Support

G 2.2.1 User Rate

The user rate (\$/MWh) for the lost opportunity cost for Voltage Support referred to in G 2.1.1 in Zone x for Trading Interval t will be calculated using the following formula:

$$VSSTRate_{xt} = \frac{\sum_{ij} VSST_{xijt}}{\sum_j QChargeVS_{xjt}}$$

The user rate (\$/MWh) for month m for long-term Voltage Support referred to in G2.1.2 in Zone x will be calculated using the following formula:

$$VSSTRate_{xm} = \frac{\sum_j VSLT_{xjm}}{\sum_{jm} QChargeVS_{xjt}}$$

G 2.2.2 Voltage Support Charges

The lost opportunity cost Voltage Support charge (\$) payable to recover the sums under G 2.1.1 for Zone x for Trading Interval t for Scheduling Coordinator j will be calculated using the following formula:

$$VSSTCharge_{xjt} = VSSTRate_{xt} * QChargeVS_{xjt}$$

The monthly long-term Voltage Support charge (\$) payable to recover sums under G 2.1.2 for Zone x for month m for Scheduling Coordinator j will be calculated using the following formula:

$$VSLTCharge_{xjm} = VSLTRate_{xm} * \sum_m QChargeVS_{xjt}$$

G 2.3 Payments to Participating Generators for Black Start

Payments to Participating Generators that provide Black Start Energy or capability shall be made in accordance with the agreements they have entered into with the ISO for the provision of Black Start services and shall be calculated as follows:

G 2.3.1 Black Start Energy Payments

Whenever a Black Start Generating Unit provides a Black Start in accordance with the ISO's instructions, the ISO will pay the Black Start Generator for that Unit for the Generating Unit's energy output and start-up costs. The ISO will pay Black Start Generator for Generating Unit i, the Black Start energy and start-up costs (\$) in Trading Interval t in accordance with the following formula:

$$BSEn_{ijt} = (EnQBS_{ijt} * EnBid_{ijt}) + BSSUP_{ijt}$$

G 2.3.2 Black Start Energy Payments to Owners of Reliability Must-Run Units

Whenever a Reliability Must-Run Unit provides a Black Start in accordance with the ISO's instructions, the ISO will pay the Scheduling Coordinator of the Reliability Must-Run Unit the Generating Unit's Energy and start-up costs. The ISO will pay Scheduling Coordinator j for Reliability Must-Run Unit i the Black Start Energy and start-up costs (\$) in Trading Interval t in accordance with the following formula:

$$BSEn_{ijt} = (EnQBS_{ijt} * EnBid_{ijt}) + (BSSUP_{ijt})$$

G 2.4 Charges to Scheduling Coordinators for Black Start

G 2.4.1 User Rate

The user rate (\$/MWh) for Black Start Energy payments referred to in G 2.3.1 and G 2.3.2 for Trading Interval t will be calculated using the following formula:

$$BSRate_t = \frac{\sum_{ij} BSEn_{ijt}}{\sum_j QChargeBlackStart_{jt}}$$

G 2.4.2 Black Start Charges

The user charge (\$/MWh) for Black Start Energy to recover the costs of payments under G 2.3.1 and G 2.3.2 for Trading Interval t for Scheduling Coordinator j will be calculated using the following formula:

$$BSCharge_{jt} = BSRate_t * QChargeBlackStart_{jt}$$

G 3 Meaning of Terms in the Formulae

G 3.1 VSST_{xijt} (\$)

The lost opportunity cost paid by the ISO to Scheduling Coordinator j for Generating Unit i in Zone x, resulting from the reduction of MW output in Trading Interval t.

G 3.2 P_{xt} (\$/MWh)

The Hourly Ex Post Price for Imbalance Energy in Trading Interval t in Zone x.

G 3.3 Sup_{xdecit} (\$/MWh)

The Supplemental Energy Bid submitted by Scheduling Coordinator j for Generating Unit i in Zone x in Trading Interval t, whose output is reduced by the ISO to provide additional short-term Voltage Support.

G 3.4 Dec_{xit} (MW)

The reduction in MW by Scheduling Coordinator j for Generating Unit i in Zone x in Trading Interval t, in order to provide short-term additional Voltage Support.

G 3.5 VSLT_{xjm} (\$)

The payment from the ISO to Scheduling Coordinator j for its Reliability Must-Run Units in Zone x for Voltage Support in month m calculated in accordance with the relevant Reliability Must-Run Contract.

G 3.6 VSSTRate_{xt} (\$/MWh)

The Trading Interval lost opportunity cost Voltage Support user rate charged by the ISO to Scheduling Coordinators for Trading Interval t for Zone x.

G 3.7 VSLTRate_{xm} (\$/MWh)

The monthly long-term Voltage Support user rate charged by the ISO to Scheduling Coordinators for month m for Zone x.

G 3.8 QChargeVS_{xjt} (MWh)

The charging quantity for Voltage Support for Scheduling Coordinator j for Trading Interval t in Zone x equal to the total metered Demand (including exports to neighboring Control Areas) for Scheduling Coordinator j in Zone x for Trading Interval t.

G 3.9 VSSTCharge_{xjt} (\$)

The lost opportunity cost Voltage Support user charge for Zone x for Trading Interval t for Scheduling Coordinator j.

G 3.10 VSLTCharge_{xjm} (\$)

The long-term charge for Voltage Support for month m for Zone x for Scheduling Coordinator j.

G 3.11 BSEn_{ijt} (\$)

The ISO payment to Scheduling Coordinator j (or Black Start Generator j) for that Generating Unit i providing Black Start Energy in Trading Interval t.

G 3.12 EnQBS_{ijt} (MWh)

The energy output, instructed by the ISO, from the Black Start capability of Generating Unit i from Scheduling Coordinator j (or Participating Generator j) for Trading Interval t.

G 3.13 EnBid_{ijt} (\$/MWh)

The price for Energy output from the Black Start capability of Generating Unit i of Scheduling Coordinator j or (Black Start Generator j) for Trading Interval t calculated in accordance with the applicable Reliability Must-Run Contract or Interim Black Start Agreement.

G 3.14 BSSUP_{ijt} (\$)

The start-up payment for a Black Start successfully made by Generating Unit i of Scheduling Coordinator j (or Black Start Generator j) in Trading Interval t calculated in accordance with the applicable Reliability Must-Run Contract or Interim Black Start Agreement.

G 3.15 BSRate_t (\$/MWh)

The Black Start Energy payment user rate charged by the ISO to Scheduling Coordinators for Trading Interval t.

G 3.16 QChargeBlackstart_{jt} (MW)

The charging quantity for Black Start for Scheduling Coordinator j for Trading Interval t equal to the total metered Demand (excluding exports to neighboring Control Areas) of Scheduling Coordinator j for Trading Interval t.

PART H
[NOT USED]

PART I
DRAFT SAMPLE OF INVOICE

Independent System Operator
MARKET INVOICE

CUSTOMER 1
 101 N. Harbor Blvd.
 Anaheim CA 92808

Invoice: 181
 Date: 20-JUN-97
 Customer Number: 1000

Please send payment to:

1000 South Fremont Avenue
 Building A-11
 Alhambra CA 91803

For all inquiries contact:
 1-800-ISO-HELP

Comments:

Charges settlement date: 20-JUN-97 to 20-JUN-97

Charge Type	Description	Amount
0001	0001-Day-Ahead Spinning Reserve due SC	-\$845.00
0002	0002-Day-Ahead Non-Spinning Reserve due SC	-\$1,025.00
0003	0003-Day-Ahead AGC/Regulation due SC	-\$1,025.00
0004	0004-Day-Ahead Replacement Reserve due SC	-\$1,385.00
0051	0051-Hour-Ahead Spinning Reserve due SC	-\$1,565.00
0052	0052-Hour-Ahead Non-Spinning Reserve due SC	-\$1,745.00
0053	0053-Hour-Ahead AGC/Regulation due SC	-\$1,925.00
0054	0054-Hour-Ahead Replacement Reserve due SC	-\$2,105.00
0101	0101-Day-Ahead Spinning Reserve due ISO	\$22,075.00
0102	0102-Day-Ahead Non-Spinning Reserve due ISO	\$23,935.00
0103	0103-Day-Ahead AGC/Regulation due ISO	\$25,795.00
0104	0104-Day-Ahead Replacement Reserve due ISO	\$27,655.00
0251	0251-Hour-Ahead Intra-Zonal Congestion Settlement due ISO	\$385.00
0252	0252-Hour-Ahead Intra-Zonal Congestion Charge/Refund due ISO	\$4,925.00
0253	0253-Hour-Ahead Inter-Zonal Congestion Settlement due ISO	\$5,285.00
0301	0301-Ex-Post A/S Energy due SC	-\$6,005.00
0302	0302-Ex-Post Supplemental Reactive Power due SC	-\$6,365.00
0303	0303-Ex-Post Replacement Reserve due ISO (Dispatched)	\$6,725.00
0304	0304-Ex-Post Replacement Reserve due ISO (Undispatched)	\$7,085.00

Invoice Total

Independent System Operator
FERC FEES INVOICE

CUSTOMER 1
101 N. Harbor Blvd.
Anaheim CA 92808

Invoice: 181
Date: 20-JUN-97
Customer Number: 1000

Please send payment to:

1000 South Fremont Avenue
Building A-11
Alhambra CA 91803

For all inquiries contact:
1-800-ISO-HELP

Comments:

Charges settlement date: 20-JUN-97 to 20-JUN-97

Charge Type	Description	Amount
[Charge type to be determined]	____ FERC Annual Charges due ISO	<u>[Sample charge]</u>
Invoice Total		<hr/> <hr/>

PART J

SETTLEMENT AND BILLING OF RELIABILITY MUST-RUN CHARGES AND PAYMENTS

1 Objectives, Definitions and Scope

1.1 Objectives

The objective of this Part J is to inform RMR Owners which are responsible for preparation of invoices, and Responsible Utilities, which are responsible for payment of Reliability Must-Run Charges pursuant to Section 30.6.1.2 of the ISO Tariff, of the manner in which the RMR Charges referred to in Section 30.6.1.1 of the ISO Tariff shall be verified and settled and of the procedures regarding the billing, invoicing and payment of these RMR Charges.

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 Part J. A reference to a paragraph is to a paragraph of this Part J. References to Parts are to Parts of Appendix N.

1.2.3 Special Definitions for this Part J

In this Part J the following words and expressions shall have the following meanings:

“Adjusted RMR Invoice” means the monthly invoice issued by the RMR Owner to the ISO for adjustments made to the Revised Estimated RMR Invoice pursuant to the RMR Contract, reflecting actual data for the billing month.

“Business Day” shall have the meaning ascribed to it in the RMR Contract.

“Estimated RMR Invoice” means the monthly invoice issued by the RMR Owner to the ISO for estimated RMR Payments or Refunds pursuant to the RMR Contract.

“Facility Trust Account” means, for each RMR Contract, the account established and operated by the ISO to and from which all payments under this Part J shall be made. Each Facility Trust Account will have two segregated commercial bank accounts, a RMR Owner Facility Trust Account and a Responsible Utility Facility Trust Account.

“Prior Period Change” means any correction, surcharge, credit, refund or other adjustment pertaining to a billing month which is discovered after the Revised Adjusted RMR Invoice for such billing month has been issued.

“Prior Period Change Worksheet” means a worksheet prepared by the RMR Owner and submitted to the ISO following discovery of a necessary change to an RMR invoice after the Revised Adjusted RMR Invoice for the billing month has been issued.

“Responsible Utility Facility Trust Account” means a segregated commercial bank account under the Facility Trust Account containing funds held in trust for the Responsible Utility.

“RMR Invoice” means any Estimated RMR Invoice, Revised Estimated RMR Invoice, Adjusted RMR Invoice, or Revised Adjusted RMR Invoice.

“RMR Owner Facility Trust Account” means a segregated commercial bank account under the Facility Trust Account containing funds held in trust for the RMR Owner.

“RMR Payment” means any amounts which the ISO is obligated to pay to RMR Owners under RMR Contracts, net of any applicable credits under RMR Contracts.

“RMR Payments Calendar” means the Payments Calendar issued by the ISO pursuant to Section 3 of this Part J.

“RMR Refund” means any amounts which RMR Owners are obligated to pay the ISO and the ISO is obligated to pay Responsible Utilities under RMR Contracts, or resulting from an order by the Federal Energy Regulatory Commission, for deposit into the Responsible Utility Facility Trust Account.

“RMR Security” means the form of security provided by a Responsible Utility to cover its liability under this Part J pursuant to Section 30.6.1.1.3 of the ISO Tariff.

1.2.4 Rules of Interpretation and Other Terms and Conventions

The rules of interpretation set out in the ISO Tariff.

1.3 Scope of Application to Parties

This Part J applies to the RMR Payments owed RMR Owners by the ISO, the RMR Charges owed by the Responsible Utilities to the ISO and the RMR Refunds owed to the ISO by RMR Owners and owed to the Responsible Utilities by the ISO for costs incurred under the RMR Contract.

For the avoidance of doubt, this Part J shall not apply to charges for Energy or Ancillary Services which are payable by the ISO under Sections 8 and 11 of the ISO Tariff to Scheduling Coordinators representing RMR Owners. Such payments shall be made by the ISO to such Scheduling Coordinators pursuant to Section 11 of the ISO Tariff and the provisions of Appendix N. The RMR Owners shall account for such payments received by or due to their Scheduling Coordinators in each RMR Invoice.

1.4 Relationship of this Part J with Appendix N

Parts B, G and H of Appendix N shall apply as appropriate to this Part J. Unless otherwise specified, other provisions of Appendix N shall not apply to this Part J.

1.5 Relationship of this Part J with the ISO Tariff

For the avoidance of doubt, Sections 11.3 to 11.24 inclusive of the ISO Tariff shall not apply to this Part J.

2 Accounts

2.1 Facility Trust Account

The ISO shall establish a Facility Trust Account for each RMR Contract. Each Facility Trust Account shall consist of two segregated commercial bank accounts: an RMR Owner Facility Trust Account, which will be held in trust for the RMR Owner, and a Responsible Utility Facility Trust Account, which will be held in trust for the Responsible Utility. RMR Charges paid by the Responsible Utility to the ISO in connection with the RMR Contract will be deposited into the RMR Owner Facility Trust Account and RMR Payments from the ISO to the RMR Owner will be withdrawn from such Account, all in accordance with this Part J, Section 30.6.1.1 of the ISO Tariff and the RMR Contract. RMR Refunds received by the ISO from the RMR Owner in accordance with the RMR Contract will be deposited into the Responsible Utility Facility Trust Account and such RMR Refunds will be withdrawn from such Account and paid to the Responsible Utility in accordance with this Part J., Section 30.6.1.1 of the ISO Tariff, and the RMR Contract. The RMR Owner Facility Trust Account and the Responsible Utility Facility Trust Account shall have no other funds commingled in them at any time.

2.2 RMR Owner's Settlement Accounts

Each RMR Owner shall establish and maintain a settlement account at a commercial bank located in the United States and reasonably acceptable to the ISO which can effect money transfers via Fed-Wire where payments to and from the Facility Trust Accounts shall be made in accordance with this Part J. Each RMR Owner shall notify the ISO of its settlement account details upon entering into its RMR Contract with the ISO and may notify the ISO from time to time of any changes by giving at least 15 days notice before the new account becomes operational.

3 RMR Payments Calendar

The ISO shall issue an RMR Payments Calendar for the purposes of this Part J which shall contain those dates set forth in Section 9.1 (b) of the RMR Contract and the following information:

- (a) the date on which RMR Owners are required to issue to the ISO, with a copy to the Responsible Utility, their Estimated RMR Invoice pursuant to their RMR Contract;
- (b) the date on which the ISO is required to initiate proposed adjustments to the Estimated RMR Invoice to the Responsible Utility and to the RMR Owner;
- (c) the date by which the RMR Owners are required to issue their Revised Estimated RMR Invoice reflecting appropriate revisions to the original Estimated RMR Invoice agreed upon by the Responsible Utility and the RMR Owner (In the event no revisions are required, Owner shall submit an e-mail to the ISO and Responsible Utility stating there are no revisions and the Estimated RMR Invoice should be deemed as the Revised Estimated RMR Invoice.);
- (d) the date on which the ISO is required to issue to the Responsible Utility or RMR Owner, with an e-mail notification to both parties, the ISO Invoice based on the Revised Estimated RMR Invoice;

- (e) the date on which RMR Owners are required to issue to the ISO, with a copy to the Responsible Utility, their Adjusted RMR Invoice pursuant to their RMR Contract;
- (f) the date on which the ISO is required to initiate proposed adjustments to the Adjusted RMR Invoice to the Responsible Utility and the RMR Owner;
- (g) the date by which the RMR Owners are required to issue their Revised Adjusted RMR Invoice reflecting appropriate revisions to the original Adjusted RMR Invoice agreed upon by the Responsible Utility and the RMR Owner. (In the event no revisions are required, Owner shall submit an e-mail to the ISO and Responsible Utility stating there are no revisions and the Adjusted RMR Invoice should be deemed as the Revised Adjusted RMR Invoice.);
- (h) the date on which the ISO is required to issue to the Responsible Utility or the RMR Owner, with an e-mail notification to both parties, the ISO Invoice based on the Revised Adjusted RMR Invoice;
- (i) the dates by which the Responsible Utility and RMR Owner must have notified the ISO of any dispute in relation to the ISO Invoice, Estimated or Adjusted RMR Invoices (including the Revised Estimated and Revised Adjusted RMR Invoice) or the ISO's proposed adjustments;
- (j) the date and time by which Responsible Utilities or RMR Owners are required to have made payments into the RMR Owner Facility Trust Account or Responsible Utility Facility Trust Account in payment of the ISO Invoices relating
to each Revised Estimated RMR Invoice and each Revised Adjusted RMR Invoice;
- (k) the date and time by which the ISO is required to have made payments into the RMR Owners' Facility Trust Accounts or Responsible Utilities' Facility Trust Accounts in payment of the Revised Estimated RMR Invoice and the Revised Adjusted RMR Invoice pursuant to their RMR Contract;

If the day on which any ISO Invoice, any RMR Invoice, or payment is due, is not a Business Day, such statement or invoice shall be issued or payment shall be due on the next succeeding Business Day.

Information relating to charges for Energy or Ancillary Services which are payable by the ISO pursuant to Sections 8 and 11 of the ISO Tariff and Appendix N to the Scheduling Coordinators representing the RMR Owners will be contained in the RMR Payments Calendar pursuant to Section 11.24.

4 Information to be provided by RMR Owners to the ISO

Each RMR Invoice and any Prior Period Change Worksheet shall include, or be accompanied by, information about RMR Payments and RMR Refunds in sufficient detail to enable the ISO to verify all RMR Charges and all RMR Refunds, and such information shall be copied to the Responsible Utility. Each RMR Invoice shall separately show the amounts due for services from each Reliability Must-Run Unit.

This information shall be provided in an electronic form in accordance with the RMR Invoice template developed jointly and agreed to by the ISO, Responsible Utilities and RMR Owners in accordance with the RMR Contracts and the principles in Schedule O to those Contracts, and maintained on the ISO Home Page.

5 Validation of RMR Charges and RMR Refunds

The ISO shall validate, based on information provided by each RMR Owner pursuant to paragraph 4, the amount due from the relevant Responsible Utility for RMR Charges and the amount due to the relevant Responsible Utility for RMR Refunds applicable to the Reliability Must-Run Generation and Ancillary Services of that RMR Owner, but shall not represent or warrant the accuracy or completeness of the information provided by the RMR Owner. The ISO shall provide copies of its exception report and information to the relevant Responsible Utility and RMR Owner.

The ISO shall not be obligated to pay the Responsible Utility any RMR Refunds unless and until the ISO has received corresponding RMR Refunds into the Responsible Utility Facility Trust Account from the RMR Owner.

6 Description of the Billing Process

6.1 Issuance of RMR Invoices by the RMR Owner

Each RMR Owner shall provide any RMR Invoice to the ISO in the electronic form, mutually agreed by the parties, which may be updated

by agreement of the ISO, Responsible Utilities and RMR Owners from time to time in accordance with the requirements of Schedule O of the RMR Contract, on each of the days specified in the RMR Payments Calendar, and shall send to the relevant Responsible Utility a copy of that invoice on the day of issue.

6.2 Review of the RMR Invoice by the ISO

The ISO shall review each RMR Invoice within the period specified in the RMR Payments Calendar and is required to initiate proposed adjustments to that invoice to the RMR Owner and the relevant Responsible Utility. Once the ISO initiates proposed adjustments, the RMR Owner shall issue a Revised Estimated RMR Invoice or Revised Adjusted RMR Invoice.

6.3 Issuance of ISO Invoices by the ISO

The ISO shall provide to the Responsible Utility and the RMR Owner on the dates specified in the RMR Payments Calendar ISO Invoices showing:

- (a) the amounts which, on the basis of the Revised Estimated RMR Invoice or the Revised Adjusted RMR Invoice, as the case may be, and pursuant to paragraph 5 of this Part J, are to be paid by or to the relevant Responsible Utility and RMR Owner;
- (b) the Payment Date, being the date on which such amounts are to be paid and the time for such payment;
- (c) details (including the account number, bank name and Fed-Wire transfer instructions) of the RMR Owner Facility Trust Account to which any amounts owed by the Responsible Utility are to be paid, or of the RMR Responsible Utility Facility Trust Account to which any amounts owed by the RMR Owner are to be paid.

6.4 Resolving Disputes Relating to Invoices

6.4.1 Review of the Invoices by the Responsible Utility

Each Responsible Utility shall have the review period specified in the RMR Payments Calendar to review RMR Invoices, and ISO Invoices, validate, and propose adjustments to such invoices and notify the ISO of any dispute. Notwithstanding the above, each Responsible Utility shall have the review time specified in ISO Tariff Section 30.6.1.1 to dispute such invoice.

6.4.2 Dispute Notice

If a Responsible Utility disputes any item or calculation relating to any Revised RMR Invoice, or any ISO Invoice, it shall provide the ISO, with a copy to the RMR Owner, via email or such other communication mode as the parties may mutually agree upon, a notice of dispute at any time from the receipt of the copy of such invoice from the RMR Owner or the ISO to the expiration of the period for review set out in Section 6.4.1. The ISO shall initiate a corresponding dispute with the RMR Owner under the RMR Contract.

6.4.3 Contents of Dispute Notice

The notice of dispute shall state clearly the Revised Estimated RMR Invoice, Revised Adjusted RMR Invoice, or ISO Invoice in dispute, the item disputed (identifying specific Reliability Must-Run Units and time periods), the reasons for the dispute, and the proposed amendment (if appropriate) and shall be accompanied by all available evidence reasonably required to support the claim.

6.4.4 Prior Period Change Agreed to by the RMR Owner

Subject to paragraph 6.4.5 or 6.4.6 of this Part J, if the RMR Owner agrees with the proposed change, the change shall be shown in a Prior Period Change Worksheet and included in the next appropriate May or December Estimated RMR Invoice as specified in Article 9.1 of the RMR Contract.

6.4.5 Dispute Involving the RMR Owner

If the dispute relates to an item originating in any RMR Invoice the applicable provisions of the RMR Contract and Section 30.6.1.1.1 of the ISO Tariff shall apply.

6.4.6 Dispute Involving an Alleged Error or Breach or Default of the ISO's Obligations Under Section 5.2.7 of the ISO Tariff

If the dispute relates to an alleged error or breach or default of the ISO's obligations under Section 30.6.1.1. of the ISO Tariff, the applicable provisions of the RMR Contract and Section 30.6.1.1.1 of the ISO Tariff shall apply.

6.4.7 Payment Pending Dispute

Subject to Section 30.6.1.1.1 of the ISO Tariff, if there is any dispute relating to an item originating in an RMR Invoice that is not resolved prior to the Payment Date, the Responsible Utility shall be obligated to pay any amounts shown in the relevant ISO Invoice on the Payment Date irrespective of whether any such dispute has been resolved or is still pending. The Responsible Utility may notify the ISO that the

payment is made under protest, in which case the ISO shall notify the RMR Owner that payment is made under protest. In accordance with Section 9.6 of the RMR Contract, if such dispute is subsequently resolved in favor of the Responsible Utility that made the payment under protest, then any amount agreed or determined to be owed by the RMR Owner to the ISO shall be repaid by the RMR Owner to the ISO, with interest at the interest rate specified in the RMR Contract from the date of payment by the ISO to the RMR Owner of the disputed amount to the date of repayment by the RMR Owner, as specified in Section 6.4.4 of this Part J. If RMR Owner does not agree to make the change pursuant to Section 6.4.4, then such repayment shall be made by ISO's deduction of such amount from the next ISO Invoices until extinguished, or if the RMR Contract has terminated, by paying a RMR Refund in such amount to the Responsible Utility Facility Trust Account, subject to the limitation of Section 30.6.1.1.1.1 of the ISO Tariff.

7 Payment Procedures

7.1 Payment Date

The Payment Date for RMR Payments to and RMR Refunds from RMR Owners shall be the Due Date specified in the RMR Contract and in the RMR Payments Calendar and the same shall be the Payment Date for the ISO and Responsible Utilities in relation to RMR Charges, provided that the RMR Owner has furnished the Responsible Utility and the ISO with the Revised Estimated RMR Invoice or the Revised Adjusted RMR Invoice no less than 9 calendar days before the Due Date. The Payment Date shall be stated on the ISO Invoice.

7.2 Payment Method

All payments and refunds by the ISO to RMR Owners and Responsible Utilities shall be made via Fed-Wire.

However, if the RMR Owner is also the Responsible Utility, at the discretion of the RMR Owner, payments and refunds may be made by memorandum account instead of wire transfer.

7.3 Payment by RMR Owners and Responsible Utilities

Each RMR Owner shall remit to the Responsible Utility Facility Trust Account the amount shown on the relevant ISO Invoice as payable by that RMR Owner not later than 10:00 am on the Payment Date.

Subject to Section 30.6.1.1 of the ISO Tariff, each Responsible Utility shall remit to the RMR Owner Facility Trust Account the amount shown on the relevant ISO Invoice not later than 10:00 am on the Payment Date.

7.4 Payment by the ISO

The ISO shall verify the amounts available for distribution to Responsible Utilities and/or RMR Owners on the Payment Date and shall give instructions to the ISO Bank to remit from the relevant Facility Trust Account to the relevant settlement account maintained by each Responsible Utility or RMR Owner the amounts determined by the ISO to be available for payment to each Responsible Utility or RMR Owner.

7.5 Payment Default by RMR Owner or Responsible Utility

If by 10.00 am on a Payment Date the ISO, in its reasonable opinion, believes that all or any part of any amount due to be remitted to the relevant Facility Trust Account by the RMR Owner or the Responsible Utility will not or has not been remitted ("the Default Amount") the ISO shall immediately notify the RMR

Owner and the Responsible Utility. Where the Default Amount was due from the Responsible Utility, the ISO and RMR Owner shall proceed as set forth in Section 30.6.1.1 of the ISO Tariff and the applicable provision of the RMR Contract. Where the Default Amount was due from the RMR Owner, the ISO and the

Responsible Utility shall proceed as set forth in the applicable provision of the RMR Contract.

7.5.1 Default relating to Market Payments

For the avoidance of doubt, non payment to RMR Owners, or their respective Scheduling Coordinators, of charges for Energy or Ancillary Services which are payable by the ISO to Scheduling Coordinators representing such RMR Owners shall be dealt with pursuant to Sections 11.3 to 11.24 (inclusive) of the ISO Tariff and the provisions of Appendix N.

7.6 Set-off

7.6.1 Set-off in the case of a defaulting Responsible Utility

The ISO is authorized to apply any amount to which any defaulting Responsible Utility is or will be entitled from the Responsible Utility Facility Trust Account in or towards the satisfaction of any amount owed by that Responsible Utility to the RMR Owner Facility Trust Account arising under the settlement and billing process set out in this Part J.

For the avoidance of doubt, neither the ISO nor any Responsible Utility will be authorized to set off any amounts owed by that Responsible Utility in respect of one Facility Trust Account against amounts owed to that Responsible Utility in respect of another Facility Trust Account or any amounts owed by that Responsible Utility under this Part J against amounts owed to that Responsible Utility except as provided by Section 30.6.1.1 of the ISO Tariff.

7.6.2 Set-off in the case of a defaulting RMR Owner

The ISO is authorized to apply any amount to which any defaulting RMR Owner is or will be entitled from the RMR Owner Facility Trust Account in or towards the satisfaction of any amount owed by that RMR Owner to the Responsible Utility Facility Trust Account in accordance with Article 9 of the RMR Contract and Sections 30.6.1.1 and 8.12 of the ISO Tariff.

For the avoidance of doubt, neither the ISO nor any RMR Owner will be authorized to set off any amounts owed by that RMR Owner in respect of one Facility Trust Account against amounts owed to that RMR Owner in respect of another Facility Trust Account or any amounts owed by that RMR Owner under this Part J against amounts owed to that RMR Owner under the RMR Contract.

7.7 Default Interest

Responsible Utilities shall pay interest on Default Amounts to the ISO at the interest rate specified in the RMR Contract for the period from the relevant Payment Date to the date on which the payment is received by the ISO.

RMR Owners shall pay interest to the ISO on Default Amounts at the interest rate specified in the RMR Contract for the period from the date on which payment was due to the date on which the payment is received by the ISO.

The ISO shall pay interest to RMR Owners at the interest rate specified in the RMR Contract for the period from the date on which payment is due under the RMR Contract to the date on which the payment is received by the RMR Owner.

The ISO shall pay interest to Responsible Utilities at the interest rate specified in the relevant RMR Contract for the period from the date following the date it received an RMR Refund from the relevant RMR Owner to the date in which the payment is received by the relevant Responsible Utility.

Where payment of a Default Amount is made by exercise of a right of set-off or deduction, payments shall be deemed received when payment of the sum which takes that set-off or deduction into account is made.

8 Overpayments

The provisions of Sections 11.18.2.a and 11.18.2.b shall apply to RMR Owners and Responsible Utilities which have been overpaid by the ISO and references to "ISO Creditors" in these sections and in the relevant Sections of the ISO Tariff shall be read, for the purposes of this Part J, to mean RMR Owners and Responsible Utilities as applicable. Disputed amounts shall not be considered to be overpayments until and unless the dispute is resolved.

9 Communications

9.1 Method of Communication

ISO Invoices will be issued by the ISO via Electronic Data Interchange ("EDI"). RMR Invoices and Prior Period Change Worksheets will be issued by the RMR Owner in an electronic form mutually agreed by the parties and maintained on the ISO's Home Page. ISO shall also post prior period change examples and prior period change guidelines as specified in Article 9.1 of the RMR Contract.

9.2 Emergency Procedures

9.2.1 Emergency Affecting the ISO

In the event of an emergency or a failure of any of the ISO software or business systems, the ISO may deem any Estimated RMR Invoice or any Adjusted RMR Invoice to be correct without thorough verification and may implement any temporary variation of the timing requirements relating to the settlement and billing process contained in this Part J.

9.2.2 Emergency Affecting the RMR Owner

In the event of an emergency or a failure of any of the RMR Owner's systems, the RMR Owner may use Estimated RMR Invoices as provided in the applicable section of the RMR Contract or may implement any temporary variation of the timing requirements relating to the settlement and billing process contained in this Part J and its RMR Contract. Details of the variation will be published on the ISO Home Page.

Communications of an emergency nature on a Due Date or a Payment Date relating to payments shall be made by the fastest practical means including by telephone.

10 Confidentiality

The provisions of Sections 11.9A, 20.5, and 11 shall apply to this Part J between and among the RMR Owners, the ISO and Responsible Utilities.

Except as may otherwise be required by applicable Law, all information and data provided by RMR Owner or the ISO to the Responsible Utility pursuant to the RMR Contract, Section 30.6.1.1 of the ISO Tariff or this Part J ("confidential information") shall be treated as confidential and proprietary to the providing party to the extent required by Section 12.5 and Schedule N of the RMR Contract and will be used by the receiving party only as permitted by such Section 12.5 and Schedule N.

11 Amendments to this Part J

If the ISO determines a need for an amendment to this Part J, the ISO shall follow the requirements as set forth in Section 22.11 of the ISO Tariff, provided that ISO may not modify Part J as it applies to any RMR contract without the consent of the relevant RMR Owner and Responsible Utility.

ISO TARIFF APPENDIX O
Metering

PART A

FAILURE OF ISO FACILITIES

A 1 WEnet Unavailable

A 1.1 Unavailable Functions of WEnet

During a total disruption of the WEnet the ISO will not be able to:

- (a) communicate with ISO Metered Entities or Scheduling Coordinators to acquire or provide any Meter Data or Settlement Quality Meter Data; and
- (b) communicate general information.

A 1.2 Communications during WEnet Unavailability

During any period of WEnet unavailability, the ISO shall:

- (a) make all reasonable efforts to provide general information to ISO Metered Entities and Scheduling Coordinators using voice communications; and
- (b) inform ISO Metered Entities and Scheduling Coordinators of the methods they must use to provide Meter Data and Settlement Quality Meter Data to the ISO during that period.

A 2 Primary MDAS Master Station Completely Unavailable

A 2.1 Notification of Loss of Primary MDAS Master Station

In the event that the primary MDAS master station becomes completely unavailable, the ISO will use alternate communications to notify the redundant MDAS master station that the primary MDAS master station is unavailable. The ISO will post information on the situation on the WEnet. Additional voice notifications will be made as time permits.

A 2.2 Notification of Restoration of Primary MDAS Master Station

The ISO will post confirmation on WEnet that all computer systems are functioning normally (if such be the case) and use the redundant MDAS master station to take complete control of the all MDAS functions. Once the primary MDAS master station is again available, all functions will be transferred back to the primary MDAS master station and the ISO will notify all ISO Metered Entities and Scheduling Coordinators via the WEnet.

PART B

CERTIFICATION PROCESS FOR METERING FACILITIES

Paragraphs B1 to B3 of this Part describe the steps that ISO Authorized Inspectors and the ISO will take to certify Metering Facilities of ISO Metered Entities.

The steps described here will also be applicable to Scheduling Coordinator Metered Entities where no certification requirements are imposed on a Scheduling Coordinator Metered Entity by its Local Regulatory Authority.

Paragraph B5 of this Part describes the manner in which requests must be made to the ISO to perform the certification of Metering Facilities.

B 1 Documentation to be Provided by ISO/Scheduling Coordinator Metered Entity

The ISO Metered Entity or Scheduling Coordinator Metered Entity shall provide the ISO and the ISO Authorized Inspector with schematic drawings (both detailed and one line) of the Metering Facilities being considered for ISO certification. Such drawings shall be dated, bear the current drawing revision number and show all wiring, connections and devices in the circuits. Drawings shall also be provided for instrument transformers to the meter and the meter to the WEnet POP.

In addition, the ISO Metered Entity or Scheduling Coordinator Metered Entity will provide the ISO and the ISO Authorized Inspector with a completed ISO Meter Certification Form (a copy of which forms part of this Part) in respect of each set of Metering Facilities being considered for ISO certification.

B 2 Documentation to be completed by the ISO Authorized Inspector

The ISO Authorized Inspector will complete an ISO approved site verification form (an internal ISO document) in relation to each set of Metering Facilities that it inspects. The site verification form and the ISO Meter Certification Form will be the official forms used to document whether Metering Facilities meet the ISO certification criteria.

If there are any discrepancies between the ISO certified drawings on file and the actual metering circuitry inspected by the ISO Authorized Inspector or the ISO, then the ISO Authorized Inspector or the ISO will document that discrepancy and revise the schematic drawings provided to the ISO. The ISO Authorized Inspector will notify the ISO of the discrepancy and give the ISO Metered Entity or Scheduling Coordinator Metered Entity a notice detailing the discrepancies within 24 hours of that notification.

B 3 Review by the ISO

The ISO will review all documentation provided to it by the ISO Metered Entity or Scheduling Coordinator Metered Entity (including the ISO Meter Certification Form) and the site verification form prepared by the ISO Authorized Inspector.

If the ISO finds that the data is incomplete or fails to meet the relevant standards referred to in the ISO Tariff and this Appendix, the ISO shall provide written notice of

the deficiencies to the ISO Metered Entity or Scheduling Coordinator Metered Entity within seven days of receiving the documentation referred to above.

If the ISO finds that the data is complete, it shall, subject to any exemptions granted under 10.3.18.5.1 in relation to providing Meter Data directly to MDAS, initiate tests to certify the MDAS interface with the relevant Metering Facilities.

Upon successful completion of the MDAS interface tests the ISO will issue a Certificate of Compliance. The ISO shall return the original schematic drawings, stamped by the ISO as approved and certified, and the original ISO Meter Certification Form and site verification form. The ISO will retain copies of these documents. Once all conditions have been satisfied to the ISO's satisfaction, the ISO shall promptly issue an original Certificate of Compliance.

B 4 Provisional Certification

If the ISO finds that:

- (a) the data provided to it by the ISO Metered Entity or Scheduling Coordinator Metered Entity is incomplete or fails to meet the relevant standards referred to in the ISO Tariff and this Appendix; or
- (b) the Metering Facilities fail the MDAS interface test,

the ISO may, at its discretion, elect to issue a provisional Certificate of Compliance in respect of those Metering Facilities. The term of and conditions on which such a provisional Certificate of Compliance is issued shall be at the ISO's discretion. However, the ISO will not issue an original Certificate of Compliance to the ISO Metered Entity until such time as all of the conditions of the provisional Certificate of Compliance have been fulfilled to the satisfaction of the ISO.

B 5 Requests for the ISO to Perform Certification

If an ISO Metered Entity would like the ISO to perform the certification of its Metering Facilities in accordance with Section 10.2.4.1, that ISO Metered Entity shall submit a written request to the ISO. The written request must:

- (a) specify the Metering Facilities to be certified;
- (b) provide the documentation referred to in paragraph B1 of this Part; and
- (c) detail the reasons why it would be impossible or impractical for the ISO Metered Entity to engage the services of an ISO Authorized Inspector to perform the certification.

The ISO will, within 14 days of receiving a request for it to certify Metering Facilities, inform the ISO Metered Entity whether it will undertake the certification or require the ISO Metered Entity to engage an ISO Authorized Inspector to perform the certification.

ISO Meter Certification Form							
Facility Information							
Name:			Unit Name:				
Address:			Drawing Numbers: (see note 1)				
ISO Metered Entity Contact :			Phone Number:				
Scheduled ISO Inspection Date:							
Generator Information							
Gross Output				Auxiliary Load			
Net Output				Voltage / Connections			
Revenue Billing Information							
Meter Manufacturer				Register Constant			
Meter Serial Number				Program ID Number			
Meter Type				Device ID			
Meter Form				IP Address/Router Port #			
Does meter have external pulse inputs for totalization purposes? Yes <input type="checkbox"/> (info. is attached) No <input type="checkbox"/>							
Internal Mass Memory Constants							
Function	Channel	K_e	PRI KWH Constant	Interval Size	Display Sequence		
KWH DELIVERED							
KVARH DEL							
KVARH REC							
KWH RECEIVED							
Voltage Transformer Information			Current Transformer Information				
Name Plate	A <input type="checkbox"/>	B <input type="checkbox"/>	C <input type="checkbox"/>	Name Plate	A <input type="checkbox"/>	B <input type="checkbox"/>	C <input type="checkbox"/>
Manufacturer				Manufacturer			
Serial Number				Serial Number			
Type				Type			

Ratio				Ratio			
Voltage Class				Voltage Class			
BIL Rating				BIL Rating			
Accuracy Class				Accuracy Class			
Burden Rating				Rating Factor			
Connected Burden				Burden Rating			
				Connected Burden			
				Applied Test Burden			
				Burden Test	Pass <input type="checkbox"/> Fail <input type="checkbox"/>	Pass <input type="checkbox"/> Fail <input type="checkbox"/>	Pass <input type="checkbox"/> Fail <input type="checkbox"/>
Instrument Transformer Correction Factors (FCF) (see note 2)							
Full Load		Power Factor			Light Load		
Line Loss Compensation Values (at Full Load Meter Rating) (see note 2 and 3)							
% Watt Fe Loss				% Var Fe Loss			
% Watt Cu Loss				% Var Cu Loss			
Total Compensation Values (at Full Load Meter Rating)							
% Watt Total Loss				% Var Total Loss			
Completed by:					Date:		
Remarks:							
Reviewed by:					Date:		

Notes:

1. ISO Metered Entities shall provide a copy of the one line diagram and schematics detailing the connections from the instrument transformer to the meter, communication circuit and local meter data server (if applicable) in accordance with this Part.
2. ISO Metered Entities shall attach a copy of the calculations used to determine these values.
3. For Power Transformer Loss Correction and Radial Line Loss Correction values the appropriate sign (+/-) should be utilized depending on the flow of Energy (delivered/received) and the location of the ISO Meter Point.

PART C

METER CONFIGURATION CRITERIA

C 1 Power Flow Conventions

Meters shall be installed and configured in such a manner so as to define the 4 Quadrants referred to in Exhibit 1 to Part D of this Appendix.

C 2 ISO Standard Meter Memory Channel Assignments

Metering Facilities shall be installed and configured in such a manner so as to comply with the following ISO requirements:

Channel 1 shall record active power delivered by the ISO Controlled Grid;

Channel 2 shall record reactive power delivered by the ISO Controlled Grid;

Channel 3 shall record reactive power received by the ISO Controlled Grid; and

Channel 4 shall record active power received by the ISO Controlled Grid.

For metering with bi-directional power flows, the ISO reserves the right to require metering which will measure 4 quadrant Vars. Situations like a generating plant that nets gross generator output and auxiliary loads on one meter which could swap from a supplying to a buying mode and vice versa may require this type of metering. To properly account for such cases, six channels of data will be required. This configuration is considered optional unless specified by ISO as required. Such Metering Facilities shall be installed and configured in such a manner so as to comply with the following ISO requirements:

Channel 1 shall record active power delivered by the ISO Controlled Grid;

Channel 2 shall record quadrant 1 reactive power delivered by the ISO Controlled Grid;

Channel 3 shall record quadrant 3 reactive power received by the ISO Controlled Grid;

Channel 4 shall record active power received by the ISO Controlled Grid;

Channel 5 shall record quadrant 2 reactive power delivered by the ISO Controlled Grid;
and

Channel 6 shall record quadrant 4 reactive power received by the ISO Controlled Grid.

C 3 ISO Standard Meter Display Modes

The following display readings shall be displayed in the normal display mode to comply with ISO requirements.

Normal Display Mode (Standard Configuration, Uni-directional/Bi-directional kWh and kVarh)

For standard metering applications the display items should be utilized in the sequence listed below. When metering uni-directional power flows, the quantities listed below that do not apply (i.e. for generation only applications, the delivered quantities should have zero accumulation) may be omitted. The only exception to this would be where the display items correlate to the load profile channel assignments. The 4 display readings that correlate to the 4 load profile channels must also be displayed.

Date MM:DD:YY.

Time HH:MM:SS (Pacific Standard Time, military format).

Total kWh delivered by the ISO Controlled Grid.

Maximum kWd (5 minute or hourly demand interval) delivered by the ISO Controlled Grid.

Date and time of maximum kWd delivered by the ISO Controlled Grid.

Total kVarh delivered by the ISO Controlled Grid.

Total kVarh received by the ISO Controlled Grid.

Total kWh received by the ISO Controlled Grid.

Maximum kWd (5 minute or hourly demand interval) received by the ISO Controlled Grid.

Date and time of maximum kWd received by the ISO Controlled Grid.

Normal Display Mode (Optional Configuration, Bi-directional Kwh and Four Quadrant kVarh)

For metering bi-directional power flows in which ISO requires optional 4 quadrant Var measurement, the following display items should be displayed in the sequence listed below:

Date MM:DD:YY.

Time HH:MM:SS (Pacific Standard time, military format).

Total kWh delivered by the ISO Controlled Grid.

Maximum kWd (5 minute or hourly demand interval) delivered by the ISO Controlled Grid.

Date and time of maximum kWd delivered by the ISO Controlled Grid.

Total kVarh for Quadrant 1.

Total kVarh for Quadrant 2.

Total kVarh for Quadrant 3.

Total kVarh for Quadrant 4.

Total kWh received by the ISO Controlled Grid.

Maximum kWd (5 minute or hourly demand interval) received by the ISO Controlled Grid.

Date and time of maximum kWd received by the ISO Controlled Grid.

Consumption Values

The consumption values shall be in XXXXX.X format and demand in XXXX.XX format. The register scaling factor should be set such that the display does not roll over in less than 60 days.

Alternative Display Mode

The values listed below should be displayed in the alternate display mode to comply with ISO requirements:

Phase A voltage magnitude and phase angle.

Phase B voltage magnitude and phase angle.

Phase C voltage magnitude and phase angle.

Phase A current magnitude and phase angle.

Phase B current magnitude and phase angle.

Phase C current magnitude and phase angle.

Neutral current magnitude and phase angle (if available).

Instantaneous kW delivered by the ISO Controlled Grid (for bi-directional power flows and/or applications where the power flow is out of ISO Controlled Grid).

Instantaneous kW received by the ISO Controlled Grid (for bi-directional power flows and/or applications where the power flow is received by the ISO Controlled Grid).

When available, the alternative display mode may also be used by ISO Metered Entities to display other definable quantities in sequence after the values defined above.

C 4 Instantaneous Power Factor - Test Mode

The following values should be displayed in the test mode to comply with ISO requirements:

total pulse count for test; and

total consumption during test.

During the test mode the above values should be provided for each function being tested (Watts, Vars). The data displayed by the meter while in test mode shall not change the normal mode display registers nor shall it be recorded in the load profile channels. This requirement is imposed to prevent the test data from being recorded as actual load/generation data.

ISO Metered Entities may add additional display quantities in sequence in the test mode after the values defined above.

C 5 Transformer and Line Loss Correction

The ISO Metered Entity will be responsible for properly calculating and applying the transformer and line loss corrections to its meters in accordance with this Appendix to reflect the actual meter usage (on the low side) as opposed to the theoretical meter usage at the transmission point.

C 6 CT/VT and Cable Loss Correction Factors

Where the connected burden of a metering circuit exceeds the burden rating of a CT or VT or if an existing instrument transformer does not meet the minimum ISO accuracy requirements, then one of the actions listed below must to be taken:

- (a) replace the instrument transformer(s) with higher burden rated revenue class units; or
- (b) reduce the burden on the circuit to comply with the name plate of existing instrument transformer(s); or
- (c) apply correction factors to the meter to adjust the meter's registration to compensate for inaccuracies.

The ISO preferred action is that referred to in paragraph (a) above.

The ISO Metered Entity will be responsible for properly calculating and applying the CT/VT and cable loss correction factors to its meters in accordance with this Appendix to adjust for inaccuracies in the metering circuit.

C 7 Special Applications, Configurations and Unique Situations

ISO Metered Entities are responsible for providing the ISO with the necessary Meter Data and other information to enable the ISO to prepare Settlement Quality Meter Data. For instance, where there is a generating plant with multiple generators and auxiliary loads, the ISO Metered Entity must provide appropriate information (i.e. documentation, descriptions, one line diagrams, etc.) to the ISO to ensure that the ISO can properly account for the net generator output of each unit under all combinations of generation and load (e.g. where only one generator is operating but all auxiliary loads are being supplied).

PART D

STANDARDS FOR METERING FACILITIES

The standards for Metering Facilities referred to in this Part provide additional details to the standards referred to in Appendix J to the ISO Tariff.

The standards referred to in Appendix J to the ISO Tariff and this Part apply to ISO Metered Entities and, where the relevant Local Regulatory Authority has not set any standards, to Scheduling Coordinator Metered Entities.

D 1 Standards for Existing Metering Facilities

Existing Metering Facilities are those facilities that are fully installed as of the ISO Operations Date. Existing Metering Facilities used by ISO Metered Entities shall meet the following general standards:

revenue quality instrument transformers at the generator output level (specifically at all main generators, banks and local distribution load supplied from the generator) must have an accuracy of 0.3% or better

generator auxiliary load metering must have an overall accuracy of 3%

revenue quality instrument transformers at transmission metering points must have an accuracy of 0.3% or better

D 2 General Standards for New Meters

New Meters are those meters that are installed after the ISO Operations Date. New Meters used by ISO Metered Entities shall meet the following general standards:

they must be revenue quality in an accuracy class of 0.25%

they must be remotely accessible, reliable, 60 Hz, three phase, bi-directional, programmable and multifunction electronic meters

they must be capable of measuring kWh and kVarh and providing calculated three phase values for kVah, kVa

they must have a demand function including cumulative, rolling, block interval demand calculation and maximum demand peaks

there must be battery back-up for maintaining RAM and a real-time clock during outages of up to thirty days

there must be AC potential indicators on each of the three phases

they must be capable of being powered either internally from the bus or externally from a standard 120 volt AC source.

they must be capable of providing MDAS (MV-90) addressable metering protocol

they must be capable of 60 days storage of kWh and KVarh interval data

If there is any inconsistency between these general standards and the detailed standards referred to in paragraphs D3 and D4 of this Part, the detailed standards shall prevail.

D 3 Detailed Standards for New Meters

Exhibit 1 to this Part provides the detailed specifications with which new meters must comply.

D 4 Detailed Standards for New Oil Filled, Wound Instrument Transformers

Exhibit 2 to this Part provides the detailed specifications with which new oil filled, wound instrument transformers must comply.

D 5 Standards for Compatible Meter Data Servers

In order for a meter data acquisition and processing system of a metered entity to be certified by the ISO as a Compatible Meter Data Server, that metered entity must satisfy the ISO that the server is capable of providing:

- Meter Data and/or Settlement Quality Meter Data to MDAS in the Meter Data Exchange Format via WEnet and/or REMnet via File Transfer Protocol (FTP);
- Meter Data to the ISO which is real data at least comparable to data obtained directly by MDAS from meters;
- Meter Data and/or Settlement Quality Meter Data to the ISO on demand within 10 minutes of receiving such a demand from the ISO;
- System Back Up procedures that permit submission of data within 41 days of a Trading Day to MDAS even in the event of a major facility or system problem. Back Up procedures must be documented and available for review by ISO.
- System Security procedures that limit the accessibility to meter data and the system parameters. The System Security procedures must be documented and available for review by ISO.
- If applicable, procedures that define methods of profiling consumption meter data into intervals. These procedures must be documented, they must follow any appropriate regulatory guidelines and they must be available for review by the ISO.
- System day-to-day operational procedures, these procedures should be available for ISO review and audit.

EXHIBIT 1 TO PART D

SPECIFICATION MTR1-96

**ENGINEERING SPECIFICATION
FOR POLYPHASE SOLID-STATE
ELECTRICITY REVENUE QUALITY METERS
FOR USE ON THE ISO CONTROLLED GRID**

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1 General Information

This Exhibit applies to all solid-state polyphase electricity meters used in revenue metering applications on the ISO Controlled Grid (Meters).

2 Scope

2.1 General

This Exhibit provides the minimum functional and performance requirements for Meters. All requirements in this Exhibit are intended to ensure the expected life cycles, security, accuracy, reliability and minimum maintenance requirement of Meters. Some requirements, however, are specified to maintain the compatibility and interchangeability of the Meter.

2.2 Applicability

Meters approved under this Exhibit may not be required to have all of the specified features. Meters shall meet the specified minimum requirements and the requirements of Section 13 (Meter Approval Testing) of this Exhibit.

3 Metering Functions

3.1 Measured Quantities

As used in this Exhibit, the term “delivered” applies to Energy flowing out of the ISO Controlled Grid and the term “received” applies to Energy flowing into the ISO Controlled Grid.

3.1.1 Consumption

The following consumption quantities are required for all Meters approved for use on the ISO Controlled Grid:

- (a) Kilowatt-hours—delivered;
- (b) Kilowatt-hours—received;
- (c) Kilo-var-hours—delivered, received, for each quadrant;
- (d) Kilovoltamp-hours—delivered, received, for each quadrant;
- (e) Ampere-squared-hours; and
- (f) Volts-squared-hours.

3.1.2 Demand

The following demand quantities are required for all meters approved for use on the ISO Controlled Grid:

- (a) Kilowatts—delivered;
- (b) Kilowatts—received;

- (c) Kilovars—delivered, received, for any quadrant; and
- (d) Kilovoltamps—delivered, received, for any quadrant.

3.1.3 Power Factors

The ISO may specify average power factors for the previous demand sub-interval in any quadrant or any combination of two quadrants.

3.1.4 Reverse Consumption/Demand

The Meter shall be programmable to take one of the following actions for reverse consumption and demand quantities:

- (a) ignore the reverse quantities; and
- (b) add the reverse quantities to the appropriate consumption and demand quantities.

3.2 Basic Default Metering Function

When power is applied to the Meter, it shall immediately begin recording bi-directional total kilowatt-hours. Reverse power flow shall carry a negative sign. This function shall be performed regardless of whether the Meter is programmed or not and shall not require a battery. An unprogrammed Meter shall indicate that it is unprogrammed. The ISO may request a Meter to be programmed with a specific program.

3.3 Demand Metering Function

Meters shall have the following demand metering functions:

- (a) as a minimum, the Meter shall be programmable for fixed and/or rolling interval demand calculations on bi-directional kilowatts and kilovars;
- (b) a battery shall not be required to perform demand calculations, to save the results or to communicate the results to a handheld meter reader connected to the optical port;
- (c) the Meter shall be programmable for one minute delivered kilowatt demand (as an approximation of “instantaneous” kilowatts delivered) in addition to the rolling interval demand calculation. The one minute demand is not required to be synchronous with the other demand quantities;
- (d) the Meter shall be programmable for rolling interval demand calculations for any optional demand quantity (see Section 3.1.2) that ISO specifies.
- (e) demand intervals shall be programmable for a duration of 5, 10, 15, 30 or 60 minutes;
- (f) the demand interval shall be composed of an integral number of sub-intervals. Sub-interval duration shall be a programmable duration of 1, 5, 10, 15 or 30 minutes;
- (g) demand functions shall be capable of temporary suspension for a programmable time interval after power is restored following a power outage. The length of time shall be programmable from zero to 60 minutes in one minute intervals;

- (h) after a demand reset, further manual demand resets shall be prevented with a programmable lockout time. A demand reset from a Meter Programmer connected to the optical port is not subject to this delay and can be initiated as frequently as required; and
- (i) if the Meter has been programmed for Time-of-Use (TOU) functions, the time at which maximum demand occurred shall be recorded at the end of that demand interval.

3.4 Time-of-Use (TOU) Metering Function

Meters shall have the following TOU metering functions:

- (a) as a minimum, the Meter shall be programmable for TOU calculations for bi-directional kilowatt-hours and kilovarhours and bi-directional kilowatt and kilovar demand.;
- (b) the Meter shall be programmable for TOU calculations for any optional consumption or demand quantity (see Section 3.1.1 or 3.1.2) that the ISO specifies;
- (c) the calendar shall be programmable into one to four mutually exclusive seasons;
- (d) each season shall be further programmable into one to four mutually exclusive daily TOU schedules;
- (e) the Meter shall be capable of distinguishing weekdays, weekends, days of the week, and holidays.
- (f) each consumption and demand quantity shall be metered independently for each TOU schedule;
- (g) only one season and one TOU schedule shall be active at a given time. There shall always be one active season and one active TOU schedule;
- (h) each daily TOU schedule shall be capable of a minimum of eight switch points with a minimum resolution of a quarter hour;
- (i) the calendar shall be capable of accommodating leap years, daylight saving time changes and recurring holidays; and
- (j) the Meter shall have capacity for a minimum calendar of 20 years, taking into account 12 holidays/year, 4 seasons/year, and 2 daylight savings time adjustments/year.

3.5 Self-Read TOU Metering Function

Meters shall have the following self-read TOU metering functions:

- (a) as a minimum the Meter shall perform a self-read of all consumption and demand quantities on season changes. A self-read shall consist of reading the quantities, resetting the demand and storing the data;
- (b) the change of season self-reads shall occur at midnight of the day before the season change;

- (c) the ISO may specify that the Meter be programmable for up to three consecutive self-reads. The self-reads shall be programmable for:
 - i. a specific day of each month at midnight;
 - ii. a specific number of days from the last demand reset (read) at midnight; and
 - iii. self-read time of use metering; and
- (d) self-read data, other than previous season data, need not be displayed but shall be retrievable with a Meter Programmer connected to the optical port.

3.6 Load Profile Function

Meters shall have the following load profile functions:

- (a) the ISO may specify that the Meter provide load profile recording of interval data for 1 to 4 channels of consumption quantities;
- (b) load recording of interval data shall operate independently of the TOU functions;
- (c) date and time shall be stored with the load recording of interval data;
- (d) load recording of interval data shall use a "wraparound" memory that stores new interval data by writing over the oldest interval data;
- (e) the load recording of interval data function shall be capable of storing and communicating a minimum of 60 days of 4 channel, 5 minute interval data, in addition to allowances for event recording (power outages, resets, time sets, etc.);
- (f) the load recording of interval data function shall have the capacity to count and store at least 16,000 counts in a 15 minute period of time; and
- (g) load recording of interval data shall continue while the Meter is communicating with a Meter Programmer connected to the optical port.

3.7 Function during Power Disturbances

Meters shall have the following functions during power disturbances:

- (a) during powerline disturbances such as brownout or outage conditions the Meter shall maintain all meter data as well as time keeping functions. Display and communication functions are not required during these conditions;
- (b) the Meter shall withstand the following outages during a continuous ten year or longer service without the need to maintain its auxiliary power system, including replacing the battery:
 - i. 20 short outages per year of less than 30 seconds per outage; and
 - ii. 40 days of continuous/cumulative outage;

- (c) during a power outage, critical program and billing data shall be written to non-volatile memory. When power is restored, data shall be returned to active memory and data collection resumed;
- (d) following a power outage, register "catch-up" time shall be a maximum of 30 seconds. During the "catch-up" time the Meter shall still calculate consumption and demand quantities. Optional outputs shall also function during this time;
- (e) during power outages, time shall be maintained with a cumulative error of no more than 2 minutes per week (0.02%);
- (f) the Meter shall record the date and time of any power outage; and
- (g) Meters may also record the duration of any power outage.

3.8 Meter Test Mode Function

Meters shall have the following meter test mode functions:

- (a) the Meter shall have the capability of a Test Mode function that suspends normal metering operation during testing so that additional consumption and demand from the tests are not added to the Meter's totals;
- (b) the Test Mode function shall be activated by a permanently mounted physical device that requires removal of the Meter cover to access or by a Meter Programmer connected to the optical port;
- (c) activation of the Test Mode shall cause all present critical billing data to be stored in non-volatile memory and restored at the time of exit from the Test Mode;
- (d) upon activation of the Test Mode, register displays shall accumulate beginning from zero;
- (e) actuation of the billing period reset device during Test Mode shall reset the test mode registers;
- (f) after a programmable time-out period, the Meter will automatically exit from Test Mode and return to normal metering; and
- (g) the default Test Mode registers for an unprogrammed meter shall include as a minimum:
 - i. time remaining in the test interval;
 - ii. maximum kilowatt block demand; and
 - iii. total kilowatt-hours.

4 Display Requirements

4.1 LCD Display

The Meter shall have an electronic display for displaying the consumption and demand quantities. A liquid crystal display (LCD) is preferred.

4.2 Viewing Characteristics

Digits for displaying the consumption and demand quantities shall be a minimum of 7/16" in height and be legible in normal daylight conditions from a distance of six feet by an observer. The viewing angle shall be a minimum of fifteen degrees from the front Meter face line of sight.

4.3 Display Components

The display shall provide the following:

- (a) six digits for display of the consumption and demand quantities and constants with decimal points for the three least significant digits;
- (b) three digits for numeric display identifiers (ID numbers);
- (c) alternate and Test Mode indication;
- (d) potential indication for each phase;
- (e) current TOU rate indicator;
- (f) end of interval indicator;
- (g) visual representation of the magnitude and direction of kilowatt loading;
- (h) visual representation of the magnitude and direction of kilovar loading if the Meter is capable of measuring kilovars; and
- (i) Annunciators for most consumption and demand quantities.

4.4 Digits

Consumption and demand quantities shall be programmable for display with leading zeroes in four, five or six digits with a decimal point at any of the least significant three digits.

4.5 Time Format

Time shall be displayed in the 24 hour military format.

4.6 Date Format

Date shall be displayed programmable in either Day/Month/Year or Month/Day/Year format.

4.7 Operating Modes

The display shall have at least three of the following operating modes:

- (a) Normal Mode – in this mode, the display shall scroll automatically through the programmed displays for normal meter reading;
- (b) Alternate Mode – in this mode, the display shall scroll automatically, scroll manually or freeze for up to one minute for alternate programmed displays;
- (c) Test Mode – in this mode, the display shall scroll automatically, scroll manually or freeze for up to one minute for test quantity displays; and
- (d) Segment Check – in this mode, all segments or displays are activated to verify display integrity.

Display ID numbers and display sequence shall be independently programmable for each of the modes referred to above. Display times shall be programmable.

4.8 Normal Mode

Upon power-up, the Meter display shall operate in the Normal Mode. The Meter display shall operate in Normal Mode until power is disconnected or until either the Alternate Mode or the Test Mode is activated.

4.9 Alternate Mode

The Alternate Mode shall be initiated with a display control device that does not require Meter cover removal or with a Meter Programmer connected to the optical port.

Display Items

As a minimum, the Meter shall provide the display quantities and items for each of the modes referred to in Section 4.7 as detailed in Attachment 2.

4.10 Constants and Correction Factors.

The Meter shall have programmable multi-variable polynomial function multipliers and/or summers to account for instrument transformer ratios, instrument transformer correction factors, the Meter constant, radial line losses and power transformer loss correction.

4.11 Identifiers

The Meter shall have programmable identifiers for the Meter ID, the person who programmed the Meter (programmer ID) and the current program ID. The Meter ID shall be capable of eight alphanumeric characters.

5 Meter Diagnostics

5.1 Self-test

The Meter register shall be capable of performing a self-test of the register software. As a minimum, the self-test shall be performed at the following times:

- (a) whenever communications are established to the register;
- (b) after a power-up; and
- (c) once per day.

5.2 Diagnostic Checks

As a minimum, the following diagnostic checks shall be performed during a self-test:

- (a) check the backup battery capacity;
- (b) verify the program integrity; and
- (c) verify the memory integrity.

5.3 Pulse Overrun

The register shall be capable of detecting that the maximum number of pulses have been exceeded during a demand interval.

5.4 Error and Warning Displays

Meters shall be capable of the following displays:

- (a) any detected error or warning shall be stored in memory and an error or warning code displayed on the display;
- (b) error code displays shall freeze the display; and
- (c) warning code displays shall be programmable to one of the following choices:
 - i. freeze the warning code on the display;
 - ii. ignore the warning code (not displayed); or
 - iii. warning code display at the end of the Normal, Alternate or Test Modes display sequences.

5.5 Error Reset

Error or warning conditions shall only be reset upon an explicit command invoked via the Meter Programmer or upon some other explicit action by the Meter technician.

6 Programming and Software

6.1 Optical Communications Interface.

The Meter shall be capable of communicating with a handheld reader (Itron DataCap or similar) through the optical port.

6.2 Meter Programmers

The ISO and ISO Authorized Inspectors will use PC DOS based laptop and handheld computers with LCD displays as meter reader/programming devices (Meter Programmers). Communications with the Meter shall be through the optical port.

6.3 Software

The ISO Metered Entity shall ensure that its supplier provides all software for maintenance, programming and operation of the Meter. The software shall include the following:

- (a) Rate Development Program;
- (b) Field Program;
- (c) Field Disk Serialization Program; and
- (d) Password protection to preclude 3rd party access for all levels of access except read-only.

6.4 Rate Development Program

The ISO Metered Entity shall ensure that its supplier provides a Rate Development Program software package which allows the ISO to customize the Meter's rate schedules and the Meter's operating parameters. The Rate Development Program shall be capable of utilizing all programmable functions of the Meter.

6.5 Rate Development Program Functions

The Rate Development Program as a minimum shall provide the following functions in a "user-friendly" manner:

- (a) originate or modify Meter configuration records;
- (b) validate user entries for format and range;
- (c) translate user entry into code for configuring the Meter;
- (d) send and receive configurations to and from the Meter;
- (e) compare configuration files from the Meter with desired files and report discrepancies;
- (f) read Meter billing data and load profile data;
- (g) generate Meter data and diagnostic reports for printing; and

- (h) generate configuration files for loading into the Meter via the Field Program.

6.6 Field Program

The ISO Metered Entity shall ensure its supplier provides a Field Program software package for use with ISO's Meter Programmer. The Field Program in conjunction with any such Meter Programmer shall be capable of loading the rate schedule and meter operating parameters as generated by the Rate Development Program into the Meter.

6.7 Field Program Functions

The Field Program as a minimum shall provide the following functions:

- (a) set date and time on the Meter;
- (b) preset the Meter consumption registers;
- (c) send and receive configurations to and from the Meter;
- (d) compare configuration files from the Meter with desired files and report discrepancies;
- (e) read Meter billing data and load profile data;
- (f) generate Meter data and diagnostic reports for printing;
- (g) read, display and modify the present settings of field configurable items;
- (h) execute a billing period reset;
- (i) reset all consumption and demand quantities; and
- (j) not have the capability to alter the configuration files as generated by the Rate Development Program.

6.8 Field Disk Serialization Program

The ISO Metered Entity shall ensure that its supplier provides a Field Disk Serialization Program software package that associates a unique password with each copy of the Field Program. The Field Disk Serialization Program shall use an ASCII text file in a specified format as input and place a different password on one or more copies of a field disk generated by the Rate Development Program.

6.9 DOS or Windows

All software programs shall be PC DOS or Windows based. The Rate Development Program shall be either a Microsoft Windows 9x application or a DOS application capable of running under Microsoft Windows 9x without any loss of function. The Field Program and the Field Disk Serialization Program shall be DOS applications capable of running under PC-DOS Version 7 or later.

6.10 Communication Protocol

The protocol used for communication with the Meter through either the optical port or the optional modem shall be an asynchronous, byte oriented protocol.

6.11 Optical Probe

The Rate Development Program and the Field Program shall support use of a compatible optical probe (ABB Unicomm or similar) connected to the standard PC serial port of the Meter Programmer.

7 Communication

7.1 Optical Port

The primary communication port to the Meter for reading and programming of the internal data shall be an optically isolated communication port per ANSI C12.13, Type 2 or other serial port.

7.2 Baud Rate

The optical port shall communicate at a minimum of 9600 baud.

7.3 Optical Port Location

The optical port shall be located in the front of the Meter and be accessible without removing the Meter's cover. The optical port shall also be functional with the Meter cover removed.

7.4 Optical Port Cable

There shall be no cable connection between the optical port on the Meter cover and the register.

7.5 RS232 or RS 485 or RSXXX.

One RSXXX port shall be provided at the Meter for bi-directional communications (with security provisions included) to computers and/or data acquisition devices. The Meter must have the capability for being polled every 15 minutes for data by MDAS or a Compatible Meter Data Server. An optional RSXXX port or ports with read-only access can be provided for others desiring the data. All RSXXX ports shall be optically isolated.

The Meter shall be capable of being polled simultaneously by more than one entity on one or more of its ports without loss of data, interference, lockup or other such problems. In all cases, priority servicing shall be given to the ISO required RSXXX port (used by MDAS).

The Meter shall support and be implementable with ISO WEnet communication chains, including:

- (a) Meter RSXXX port to ISDN line (or lease line) to ATM Cloud POP to MDAS; and
- (b) Meter RSXXX port to Compatible Meter Data Server to Frame Relay or ISDN line to ATM Cloud POP to MDAS.

8 Optional Meter Functions

8.1 Pulse Outputs

The ISO may specify one to four channels of pulse outputs that are proportional to the consumption quantities. The pulse output values shall be programmable with pulse durations of at least 100 milliseconds. The outputs may be either 2-wire, Form A or 3-wire, Form C configuration.

8.2 Current Loop

The ISO may specify an additional serial communication port consisting of a 2-wire, 20 milliamp current loop that is optically isolated from the rest of the Meter. At a minimum, the baud rate shall be selectable as 300/ 1200/ 2400/ 9600 baud.

8.3 Internal Modem

The ISO may specify an internal modem having telephone communications at autobaud rates of up to 28800 baud. The modem shall include automatic baud select, configurable answer time window and configurable answer ringcounter. The ring detect circuitry shall not be affected by spurious voltage rises in the telephone line.

8.4 Demand Threshold Alarm

The ISO may specify a kilowatt threshold relay that closes at a programmable demand value and stays closed for the remainder of the interval and until at least one complete interval does not exceed the threshold value. The value shall be independently programmable for each TOU rate season and schedule.

9 Accuracy

9.1 ANSI C12.10

The Meter shall meet or exceed the accuracy specifications contained in ANSI C12.10 over its entire service life without the need for adjustment.

9.2 Factory Calibration

The Meter shall be calibrated to provide the following level of accuracy:

- (a) $\pm 0.2\%$ at full load at power factor of 100%;
- (b) $\pm 0.25\%$ at full load at power factor of 50% lag;
- (c) $\pm 0.25\%$ at full load power factor at 50% lead; and
- (d) $\pm 0.25\%$ at light load at power factor of 100%.

9.3 Test Equipment

Meter accuracy and calibration tests, both shop and field, shall require only standard test equipment. No special laboratory-type test equipment or test procedures shall be required to assure accuracy of the Meter.

9.4 Creep

The Meter shall not creep. No pulse generation or registration shall occur for any consumption or demand quantity which depends on current while the current circuit is open.

9.5 Starting Current

The Meter shall start to calculate consumption and demand quantities when the per phase current reaches Class 20 - 5 milliamps.

9.6 Start-up Delay

The Meter shall start to calculate consumption and demand quantities less than 3 seconds after power application.

9.7 Pulse Outputs

Pulse outputs shall have the same accuracy as the Meter displays.

10 Electrical Requirements

10.1 Meter Forms, Voltage Ratings and Classes

The following forms, voltage ratings and classes of Meters are approved for installation on the ISO Controlled Grid:

- (a) A – Base Type, FORMS 5A and 9A, 120 Volts, Class 10 and Class 20;
- (b) Socket – Type, FORMS 5S and 9S, 120 Volts, Class 10 and Class 20;
- (c) Switchboard – Type, 2 Element and 3 Element, 120 Volts, Class 10 & Class 20; and
- (d) Rack mounted meter assemblies – 2 element and 3 element, Class 10 & Class 20.

10.2 Circuit Boards

All circuit boards in the Meter shall be designed to meet ISO's environmental and electrical testing requirements and the service life and performance expectations detailed in this Exhibit.

10.3 LCD Display Connectors

Gold pins encased in an elastomer or carbonized contacts, or some other better construction, shall be used to connect the LCD display to the register circuit board.

10.4 Metering Application

The Meter shall be used to meter electrical service on a continuous duty.

10.5 Connections

The Meter's internal electrical connections shall be in accordance with ANSI C12.10.

10.6 Meter Register Power Supply

The Meter register shall be powered from the line side of the Meter and shall have provision for external backup power. Neither the normal power supply nor the backup power supply (when so equipped) shall be fused.

10.7 Clock

Clocks shall meet the following requirements:

- (a) the clock internal to the Meter shall be accurate within 2 minutes per week (0.02%) when not synchronized to the ISO Controlled Grid operation line frequency and shall be resettable through the ISO communications interface. The ISO will transmit a periodic master synchronizing signal to the meter;
- (b) the internal clock shall have two modes of operation as follows:
 - i. the clock shall synchronize with the ISO Controlled Grid operation line frequency until an outage occurs. During the outage, the clock will then synchronize with its own internal crystal. When power returns, the clock shall resynchronize with the ISO's master synchronizing signal and follow line frequency; and
 - ii. the clock shall always synchronize with its own internal crystal, as a default; and
- (c) the choice of clock mode shall be programmable.

10.8 Batteries

Batteries shall meet the following requirements:

- (a) when the Meter design requires a battery as auxiliary power supply, the requirements of Section 3.7 shall apply;
- (b) the battery shall be secured with a holder securely attached to the Meter. The battery holder and electrical connections shall be designed to prevent the battery from being installed with reversed polarity;
- (c) replaceable batteries shall be easily accessible by removing the Meter cover. Battery replacement while the Meter is in service shall not interfere with any of the specified functions;
- (d) no fuse external to the battery shall be installed in the battery circuit;

- (e) the Meter battery shall provide a minimum carryover capability at 23° C for the functions listed in Section 3.7 and have a 15 year shelf life; and
- (f) the following information shall be clearly identified on the battery:
 - i. manufacturer;
 - ii. date of manufacture, including year and month (i.e. 9601) or year and week (i.e. 9644);
 - iii. polarity;
 - iv. voltage rating; and
 - v. type.

10.9 Electromagnetic Compatibility

The Meter shall be designed in such a way that conducted or radiated electromagnetic disturbances as well as electrostatic discharges do not damage nor substantially influence the Meter.

10.10 Radio Interference Suppression

The Meter shall:

- (a) not generate conducted or radiated radio frequency noise which could interfere with other equipment; and
- (b) meet FCC Part 15 Class B computing device radio frequency interference standards.

11 Mechanical Requirements

11.1 General

The Meter shall not pose any danger when operating under rated conditions in its normal working position. Particular attention should be paid to the following:

- (a) personnel protection against electric shock;
- (b) personnel protection against effects of excessive temperature;
- (c) protection against the spread of fire; and
- (d) protection against penetration of solid objects, dust or water.

11.2 Corrosion Protection

All parts of the Meter shall be effectively protected against corrosion under normal operating conditions. Protective coatings shall not be damaged by ordinary handling nor damaged due to exposure to air. The Meter shall be capable of operating in atmospheres of up to (and including) 95% relative humidity condensing.

11.3 Solar Radiation

The functions of the Meter shall not be impaired, the appearance of the Meter shall not be altered and the legibility of the Meter nameplate and other labels shall not be reduced due to exposure to solar radiation throughout the service life of the Meter.

11.4 Corrosive Atmospheres

ISO may specify additional requirements for Meters used in corrosive atmospheres.

11.5 Meter Package

The Meter Package shall meet the following requirements:

- (a) the socket Meter's dimensions shall be in accordance with ANSI C12.10;
- (b) the socket Meter shall be designed for mounting outdoors in a standard meter socket;
- (c) Meters shall have a twist-on self locking cover in accordance with ANSI C12.10 requirements. The Meter cover shall:
 - i. not contain a metal or conducting locking ring;
 - ii. shall be resistant to ultraviolet radiation;
 - iii. be sealed in such a way that the internal parts of the Meter are accessible only after breaking the seal(s);
 - iv. for any non-permanent cover deformation, not prevent the satisfactory operation of the meter;
 - v. for the "sprue" hole (mold fill hole), not affect the ability to read the Meter; and
 - vi. have an optical port per ANSI C12.13, Type 2.
- (d) the method of securing the socket Meter to the meter socket shall be with either a sealing ring or a high security sealing device;
- (e) the billing period demand reset device shall accommodate a standard electric meter seal and shall remain in place with friction if not sealed; and
- (f) filtered ventilation shall be provided in the base of the Meter to prevent condensation inside the Meter.

11.6 Nameplate

The Meter nameplate shall:

- (a) comply with the minimum information requirements of ANSI C12.10;
- (b) include the Meter's serial number and the date of manufacture. The manufacturing date shall include the year and month (i.e. 9601) or the year and week (i.e. 9644);

- (c) have the following attributes:
 - i. it shall be mounted on the front of the Meter;
 - ii. it shall not be attached to the removable Meter cover;
 - iii. it shall be readable when the Meter is installed in the Meter socket or panel; and
 - iv. it shall not impair access for accuracy adjustment or field replacement of components (such as the battery).
- (d) include ANSI standard bar coding; and
- (e) include an easily erasable strip with minimum dimensions of 3/8 inch by 1½ inches for penciling in items such as meter multiplier or the Meter tester's initials.

12 Security

12.1 Billing Period Reset

Operation of the billing period demand reset mechanism shall require breaking of a mechanical sealing device. Use of common utility-type sealing devices shall be accommodated.

12.2 Meter Password

The Meter shall be programmable by the Meter Programmer with up to four unique passwords to prevent unauthorized tampering by use of the optical port or the optional modem. For meters procured after 1/1/98, passwords must be a minimum of four (4) alpha/numeric characters. Access rights and capabilities shall be individually programmable for each password. The Meter shall accept multiple requests from different sources without error, lockup or loss of data.

12.3 Test Mode

Removal of the Meter cover shall be required to activate the Test Mode.

12.4 Program Security

At least four levels of security shall be available for the Rate Development Program and the Field Program. These levels include:

- (a) Read Register— the user can only read billing and load profile data;
- (b) Read Register— the user can only read billing and load profile data, and perform a billing period reset;
- (c) Read/Modify Register— the user can perform functions listed in 12.4(a) and 12.4(b), plus download Meter configuration files and operate other features of the Field Program; and
- (d) Read/Modify/Program Register— the user can perform functions listed in 12.4(a), 12.4(b) and 12.4(c), plus develop Meter configuration files and operate additional features of the Rate Development Program.

12.5 Revenue Protection

Meters that help prevent Energy diversion are preferred.

13 Meter Approval Testing

13.1 General Requirement

This Section outlines the testing required by the ISO to assure the quality of Meters, the ISO will not approve Meters which have not undergone the testing referred to in this Section.

ISO Testing using Independent Laboratory

In addition to the required manufacturer testing specified in this Section, the ISO reserves the right to require independent laboratory test data resulting from the performance of tests as outlined in this Section.

In addition to the applicable testing requirements of the ANSI C12 standards, the qualification tests specified in this Section shall be conducted to confirm correct operation of the Meter. The qualification testing is required for new Meter designs and for Meter product changes.

The ISO Metered Entity shall ensure that its supplier provides a certified test report documenting the tests and their results. The test report will be signed by the supplier and shall include all charts, graphs and data recorded during testing.

13.2 Meter Failure Definition

A Meter shall be designated as failed if any of the following events occur:

- (a) failure of the Meter to perform all of the specified functions;
- (b) failure of the Meter to meet the technical performance specifications included in this Exhibit;
- (c) signs of physical damage or performance degradation as a result of a test procedure, including effects which could shorten the service life of the Meter;
- (d) the occurrence of an unexpected change of state, loss of data or other unacceptable mode of operation for the Meter as a consequence of a test procedure; and
- (e) failures shall be classified as a hardware, firmware or software failure or a combination according to the following definitions:
 - i. firmware failures are errors made during the fabrication of programmable read only memory (PROM) chips such that the required program or instruction set that the microprocessor is to perform is incorrect;
 - ii. hardware failures are failures that are physical in nature and directly traceable to the component level. Visual observances such as discoloration, cracking, hardening of cables, poor solder joints, etc. are also included. Failures of DIP switches, jumpers, and links are also included; and

- iii. software failures are failures such as the loss or unintended change of data, the inability to program the Meter, the loss of the Meter program or the erroneous output or display of false information.

13.3 Meter Design Rejection Criteria

A Meter design will be rejected if any of the following events occur:

- (a) the failure of one Meter during one test procedure and the failure of a second Meter during another test procedure; and

the failure of two or more Meters during the same test procedure.

13.4 Test Setup

- (a) the Meter shall be connected to its normal operating supply voltage with a fully charged Power Failure Backup System. The Meter shall be energized throughout the duration of the test procedures, unless otherwise stated;
- (b) before testing commences, the Meter shall be energized for a minimum of two hours at room temperature;
- (c) all tests shall be conducted at room temperature unless otherwise specified; and
- (d) the Meter shall be loaded to the nameplate test amperes at 100% power factor for all tests unless otherwise indicated.

13.5 Functional Test (No Load Test)

This test confirms the operation of the Meter functions in accordance with this Exhibit:

- (a) the Meter shall be energized with no load;
- (b) the Meter shall be programmed with the ISO supplied parameters using a Meter Programmer;
- (c) operation of the specified functions will be verified over 24 hours by observing the Meter display and by interrogating the contents of Meter registers via a Meter Programmer; and
- (d) to pass this test, the Meter shall operate as specified with no observed anomalies.

13.6 Accuracy Test

This test confirms the accuracy of the Meter:

- (a) the accuracy of the Meter shall be tested for all combinations of the following conditions:
 - i. at ambient temperature, 85°C and -20°C;
 - ii. at power factors of 100%, 50% lag and 50% lead; and

- iii. at 0% to 120% of class current;
- (b) accuracy curves shall be provided for all combinations of the conditions; and
- (c) to pass this test, the Meter shall have the indicated accuracy at ambient temperature for the following load conditions:
 - i. $\pm 0.2\%$ at Full load at power factor of 100%;
 - ii. $\pm 0.25\%$ at Full load at power factor of 50% lag;
 - iii. $\pm 0.25\%$ at Full load at power factor of 50% lead; and
 - iv. $\pm 0.25\%$ at Light load at power factor of 100%.

13.7 Line Voltage Variation Test

This test confirms the Meter's correct operation under varying line voltage conditions:

- (a) the Meter shall be tested at line voltages ranging from 80% to 120% of rated voltage under the following load conditions:
 - i. full load at power factor of 100%; and
 - ii. light load at power factor of 100%; and
- (b) to pass this test the Meter shall meet the following criteria:
 - i. operate as specified;
 - ii. have an accuracy as specified in Section 13.6(c) throughout the 80% to 120% voltage range; and
 - iii. the Power Failure Backup System shall not take over when the voltage is above 80% and below 120% of rated.

13.8 Momentary Power Loss

This test confirms the Meter's ability to withstand momentary power outages:

- (a) the test will be performed by opening the AC power supply input for the specified duration;
- (b) twelve tests shall be conducted using the following sequence:
 - i. energize the Meter;
 - ii. simulate a power loss of 0.5 cycles at 60 hertz;
 - iii. lengthen each succeeding simulated power outage by 0.5 cycles until a duration of 6.0 cycles is attained; and

- iv. the start of each successive test shall be delayed by one minute; and
- (c) to pass this test, the Meter shall operate as specified with no observed anomalies.

13.9 Power Failure Backup System Test

This test confirms the carryover capability of the Power Failure Backup System:

- (a) this test shall be conducted at ambient temperature using a new or fully charged battery;
- (b) the test shall be conducted using the following sequence:
 - i. Energize the Meter at full load for two hours;
 - ii. De-energize the Meter for 24 hours; and
 - iii. Verify the integrity of programs and metering data stored in memory; and
- (c) to pass this test, the Meter shall operate as specified with no observed anomalies.

13.10 Brownout and Extended Low Voltage Test

This test confirms the Meter's ability to withstand brownouts and extended low voltage conditions:

- (a) the test shall be conducted using the following sequence:
 - i. Energize the Meter and verify correct operation;
 - ii. Slowly lower the line voltage to 80% of nominal;
 - iii. Operate the Meter at this voltage level for 6 hours;
 - iv. Verify correct Meter operation;
 - v. Lower the line voltage to 50% of nominal;
 - vi. Operate the Meter at this voltage level for 6 hours; and
 - vii. Verify correct operation of the Meter and the Power Failure Backup System; and
- (b) to pass this test, the Meter shall operate as specified with no observed anomalies.

13.11 Effect of Power Failure Backup System Voltage Variation on Clock Accuracy

This test confirms the effects of the battery voltage on the Meter's clock accuracy:

- (a) the Meter shall be tested with the battery disconnected and an auxiliary DC power supply connected to the battery carryover circuit. The DC power shall be varied from 95% to 105% of nominal battery voltage; and

- (b) to pass this test, the accuracy of the Meter clock shall be within 0.02% (2 minutes per week) with a voltage variation of 5 % of nominal battery voltage at ambient temperature.

13.12 Effect of Temperature Variation on Clock Accuracy

This test confirms the effects of temperature on the Meter clock accuracy:

- (a) this test shall be conducted with the register in the battery carryover mode;
- (b) the temperature shall be varied from 85°C to -20°C;
- (c) the Meter shall be exposed to each temperature for a least 2 hours prior to testing; and
- (d) to pass this test, the accuracy of the Meter clock shall be within 0.02% (2 minutes per week) at ambient temperature, 85°C, and -20°C.

13.13 Temperature Cycle Test

This test confirms the effects of an accelerated temperature cycle on the Meter:

- (a) the Meter cover shall be removed during this test;
- (b) the test duration shall be 7 days (168 hours);
- (c) the temperature shall be cycled once per 24 hour period;
- (d) temperature shall be varied linearly during the tests at a constant rate not to exceed 20°C per hour;
- (e) humidity shall not be controlled during the test;
- (f) the Meter shall be de-energized during the fourth and fifth cycles of the test to verify the performance of the Power Failure Backup System during temperature fluctuations;
- (g) each 24 hour cycle shall consist of the following:
 - i. begin test at +20°C (or room temperature if within 5°C);
 - ii. ramp up to +85°C in approximately 3.25 hours;
 - iii. hold at +85°C for approximately 10.75 hours;
 - iv. ramp down to -20 C in approximately 5.25 hours;
 - v. hold at -20°C for approximately 2.75 hours;
 - vi. ramp up to +20°C in approximately 2.00 hours; and
 - vii. begin next 24 hour cycle or end test after 7 cycles; and
- (h) to pass this test, the Meter shall operate as specified with no observed anomalies for the entire test period.

13.14 Humidity Cycle Test

This test confirms the effects of an accelerated humidity cycle on the Meter:

- (a) the Meter cover shall be removed during this test, or a meter cover with a large hole at the bottom may be substituted;
- (b) the duration of the test shall be 24 hours;
- (c) condensation may form on the Meter during the test;
- (d) temperature shall be varied linearly during the tests at a constant rate not to exceed 20°C per hour;
- (e) humidity shall not be controlled during temperature changes;
- (f) the test shall consist of the following sequence:
 - i. begin at +20°C (or room temperature if within 5°C);
 - ii. ramp up to +85°C in approximately 3.25 hours;
 - iii. ramp up to a relative humidity of 95% in approximately 1 hour;
 - iv. hold at +85°C at a relative humidity of 95% ±1% for approximately 14.5 hours;
 - v. ramp down to +20°C in approximately 3.25 hours;
 - vi. concurrently with Section 13.14(f)v. ramp down to a relative humidity of 75% in approximately 15 minutes;
 - vii. hold relative humidity at 75% for remainder of temperature ramp down; and
 - viii. hold at 20°C at a relative humidity of 75% ±1% for approximately 2 hours; and
- (g) to pass this test, the Meter shall operate as specified with no observed anomalies for the entire test period.

13.15 Insulation Withstand Test

This test confirms the insulation levels of the Meter:

- (a) the Meter shall not be energized for this test;
- (b) the insulation between power line voltage and current carrying parts and any other metallic or conductive part shall be tested by applying 2500 volts rms, 60 Hz for a period of one minute; and
- (c) to pass this test the leakage current shall not exceed one milliamp for the duration of the test and the Meter shall operate after completion of the test.

13.16 Standard Waveform Surge Withstand Test

This test confirms the ability of the Meter to withstand voltage transients:

- (a) the Meter shall be energized but not loaded during the test;
- (b) the test shall be conducted in accordance with the latest recognized industry standards;
- (c) the oscillatory test wave shall be applied at a repetition rate of 100 tests per second for 25 seconds;
- (d) the test signal shall be applied in both the common and transverse modes;
- (e) the test shall be conducted on all voltage, current, and optional equipment inputs and outputs;
- (f) this test will be performed two times with a maximum period of 1 minute between tests; and
- (g) to pass this test, the Meter shall operate as specified with no observed anomalies;

13.17 Fast Transient Waveform Surge Withstand Test

This test confirms the ability of the Meter to withstand fast voltage transients:

- (a) the Meter shall be energized but not loaded during the test;
- (b) this test shall be conducted in accordance with the latest industry recognized standard;
- (c) the unipolar test wave shall be applied at a repetition rate of 100 tests per second for 25 seconds;
- (d) the test signal shall be applied in both the common and transverse modes;
- (e) the test shall be conducted on all voltage, current, and optional equipment inputs and outputs;
- (f) this test will be performed two times with a maximum period of 1 minute between tests; and
- (g) to pass this test, the Meter shall operate as specified with no observed anomalies.

13.18 Powerline Surge Voltage and Current Test

This test confirms the ability of the Meter to withstand power line voltage and current surges:

- (a) the meter shall be energized but not loaded during the test;
- (b) the test shall be performed using the unipolar and the ring waveform specified in the latest industry recognized standard;

- (c) the test surges shall be applied to the power line in both the normal and common modes;
- (d) the following number of surges shall be applied at the indicated voltages:
 - i. 12 surges at 6 kV;
 - ii. 12 surges at 5 kV; and
 - iii. 36 surges at 4 kV.
- (e) the first test surges at 5 kV and 6 kV shall be injected at 0 degrees on the positive half-cycle of the waveform. Each successive test surge shall be shifted 15 degrees on the positive half-cycle of the waveform up to 180 degrees;
- (f) the first test surge at 4 kV shall be injected at 0 degrees on the positive half-cycle of the waveform. Each successive test surge shall be shifted 15 degrees on both the positive and negative half-cycles of the waveform up to 360 degrees;
- (g) sufficient time shall be allowed in between test surges for the electronic components to return to normal operating temperatures. A minimum of 5 minutes shall be allowed between each surge test;
- (h) the applied test signals shall be monitored and recorded. The Meter under test shall be monitored to confirm that correct operation is maintained;
- (i) after the tests each meter shall be inspected for visible damage, such as signs of arcing, etc.; and
- (j) to pass this test, the Meter shall operate as specified with no visible damage observed.

13.19 Electrostatic Susceptibility Test

This test verifies the ability of the Meter to withstand electrostatic discharges:

- (a) this test shall be tested in accordance with the latest revision of Military Handbook DOD-HDBK-263;
- (b) the test generator shall simulate a human body with a capacitance of 100 picofarads and a series resistance of 1500 ohms;
- (c) the test probe shall be a 3/8 inch rod with a rounded tip;
- (d) the following procedures shall be followed:
 - i. test all surfaces, including switches and buttons and other components that will be contacted by personnel under normal handling, installation and use of the Meter. This shall include any safety grounded or neutral terminals on the exterior of the meter enclosure;
 - ii. with the test probe voltage set at 10 kV, contact each of the above surfaces with the probe;

- iii. with the test probe voltage set to 15 kV, locate the probe to within approximately 0.5 inch (avoiding contact) with each of the above surfaces; and
- iv. the functions of the Meter shall be periodically verified for correct operation; and
- (e) to pass this test, the Meter shall operate as specified with no observed anomalies.

13.20 Visual Inspection

This test shall be performed after all of the other tests except the Shipping Test have been performed:

- (a) visual inspection shall be performed for all electronic circuit boards in the Meter; and
- (b) to pass this test, the Meter shall not have any defect which would result in rejection under the latest recognized industry standards on any electronic circuit board.

13.21 Shipping Test

This test confirms the ability of the Meter and its packaging to withstand the rigors of shipping and handling:

- (a) the Meter shall not be energized during this test, but shall be programmed and operating in the power Backup mode;
- (b) the packaged Meter shall be subjected to the following tests:
 - i. the National/International Safe Transit Association Pre-shipment Test Procedures, Project IA; and
 - ii. Method B, Single Container Resonance Test, of the latest revision of American Society for Testing and Materials (ASTM) Standard D-999. Test intensities, frequency ranges and test durations shall meet or exceed the recommended values of ASTM D-999; and
- (c) to pass this test, the Meter shall be inspected and tested to verify that no damage had occurred and that the time and all stored data is correct.

14 Safety

14.1 Hazardous Voltage

Hazardous voltages shall not be easily accessible with the Meter cover removed.

14.2 Grounding

All accessible conductive parts on the exterior of the Meter and conductive parts that are accessible upon removal of the Meter cover shall be electrically connected to the Meter grounding tabs. All connections in the grounding circuit shall be made with an effective bonding technique.

14.3 Toxic Materials

No materials that are toxic to life or harmful to the environment shall be exposed in the Meter during normal use.

14.4 Fire Hazard

Materials used in the construction of the Meter shall not create a fire hazard.

15 Data Security And Performance

- (a) Manual access for changing data or reprogramming shall require the physical removal or breaking of an ISO seal by the ISO or an ISO Authorized Inspector.
- (b) No loss of data shall occur as a result of the following events within design specifications:
 - i. power outages, frequency changes, transients, harmonics, reprogramming, reading; and
 - ii. environmental factors—dampness, heat, cold, vibration, dust.
- (c) 5-minute interval data for the most recent 60 day period shall always be available and accessible via the communications interface or the optical interface.

16 Documentation

16.1 Hardware Documentation To Be Provided For ISO Review

- (a) Drawing(s) showing the external meter connections.
- (b) Instruction booklets detailing the necessary procedures and precautions for installation of the Meter provided for use by field personnel during initial installation written in the style of a step by step outline.
- (c) One (1) technical/maintenance manual and one (1) repair manual shall be provided for each Meter style. These manuals shall be sufficiently detailed so that circuit operation can be understood and equipment repair facilitated.
- (d) The above documents shall be submitted for approval by ISO before equipment is installed. Approval of documents by the ISO shall not relieve any responsibility for complying with all the requirements of this Exhibit.

16.2 Software

A complete set of manuals detailing the operation of the Rate Development Program, the Field Program, and the Field Disk Serialization Program shall be provided to ISO for review. These manuals shall explain to a person with only basic computer knowledge how to generate and download Meter configuration files.

17 Applicable Standards

The standards referred to in Appendix J to the ISO Tariff shall apply to all Meters.

18 Definitions

The following terms and expressions used in this Exhibit are detailed as set forth below:

“Ambient Temperature” means temperature of $23^{\circ}\pm 2^{\circ}$ Celsius.

“Average Power Factor” means the power factor calculated using the average active and reactive power flows over the latest demand interval.

“Delivered” means Energy (active, reactive, or apparent) that flows from the ISO Controlled Grid to an End-User.

“Failed Meter” means a Meter in which any part or component, except the removable battery, has failed.

“Failure” means any hardware, firmware or software failure, or any combination.

“Field Disk Serialization Program” means a software package that allows the user to assign a separate password to each disk copy of the Field Program.

“Field Program” means a software package that allows the user to download Meter configuration files into the Meter and perform other testing and maintenance activities.

“Hazardous Voltage” means any voltage exceeding 30 volts rms.

“Meter” means all single phase and three phase electricity meters with electronic registers, including hybrid and solid state meters, but excluding solid state recorders, and including any optional devices included under the Meter cover.

“Meter Programmer” means the PC DOS based laptop computers used for meter reading/programming.

“MSDS” means the Material Safety Data Sheet.

“Power Failure Backup System” means a sub-system in the Meter that provides power to the electronic circuitry when the normal power line voltage is below operating limits. The sub-system usually consists of a battery and may or may not include a super capacitor.

“Quadrant” means the term used to represent the direction of power flows (active and reactive) between the ISO Controlled Grid and an End-User. The 4 quadrants are defined as follows:

- (a) Quadrant 1 – shall measure active power and reactive power delivered by the ISO Controlled Grid;
- (b) Quadrant 2 – shall measure active power received by ISO Controlled Grid and reactive power delivered by the ISO Controlled Grid;
- (c) Quadrant 3 – shall measure active power and reactive power received by the ISO Controlled Grid; and
- (d) Quadrant 4 – shall measure active power delivered by ISO Controlled Grid and reactive power received by the ISO Controlled Grid.

“Rate Development Program” means a software package that allows the user to generate Meter configuration files including operating parameters and TOU schedules.

“Received” means Energy (active, reactive or apparent) that flows from a Generator to the ISO Controlled Grid.

“RFI” means the Radio Frequency Interference.

“Temperature tolerance” means $\pm 2^{\circ}$ Celsius.

Attachment 1
Physical and Electronic Attribute Criterion for Electricity Meters

Test / Inspection Description	Pass	Fail
1. Bayonets A. Missing or loose parts, i.e., cotter pin, arc gap, etc.		
2. Meter Base A. Any cracked and/or missing/damaged gasket B. Any broken leg C. Missing or loose voltage link or screw D. Any missing or loose arc gaps E. Missing or damaged ventilation screen or filter on applicable meter F. Sealing hole unusable for sealing G. Any chips on upper half of meter (gasket ring area) H. Any chips which may jeopardize meter integrity I. Any sign of water damage in meter such as corrosion, oxidation, stain J. Missing or loose rivets holding frame to base		
3. Meter Frame A. Nameplate data incorrect or flawed B. Missing or loose hardware on frame		
4. Module A. Loose or defective power connectors B. Improper routing of voltage leads C. Improper fit (loose or crooked) D. Crimped or pinched voltage leads E. Incorrect module F. Calibration screw access should not be significantly affected (or covered)		
5. Meter Cover A. Wiring to communication port is correct & solid B. Proper meter cover is used for meter type and class C. Mechanical reset mechanism works properly D. Proper alignment, positioning, and operation of all cover mechanisms		

Attachment 1
Physical and Electronic Attribute Criterion for Electricity Meters (cont.)

6. Electronic Register		
A. Program register to verify acceptance of rate schedule		
B. Check display that all segments are operational		
C. Check battery carryover function, if appropriate		
D. Check register tracking by inputting disk revolutions		
E. Check for any visual defects in the register assembly		

Only scratches and/or chips that are cosmetically or functionally objectionable will be classified as defective and failing.

Attachment 2
Meter Display Items

Display Item	Normal Mode	Alternate Mode	Test Mode
Minimum Requirements for Delivered kWh			
Complete Display (Segment) Test	x	x	
Demand Reset Count		x	
Demand Reset Date		x	
Instantaneous kW	x	x	
Interval length		x	
Minutes of Battery Use		x	
Present time	x	x	
Previous Billing Rate A kWh		x	
Previous Billing Rate A Maximum kW		x	
Previous Billing Rate B kWh		x	
Previous Billing Rate B Maximum kW		x	
Previous Billing Rate C kWh		x	
Previous Billing Rate C Maximum kW		x	
Previous Billing Rate D kWh		x	
Previous Billing Rate D Maximum kW		x	
Previous Billing Total kWh		x	
Previous Season Rate A kWh	x	x	
Previous Season Rate A Maximum kW	x	x	
Previous Season Rate B kWh	x	x	
Previous Season Rate B Maximum kW	x	x	
Previous Season Rate C kWh	x	x	
Previous Season Rate C Maximum kW	x	x	
Previous Season Rate D kWh	x	x	
Previous Season Rate D Maximum kW	x	x	
Previous Season Total kWh		x	
Program ID		x	
Rate A kWh	x	x	
Rate A Maximum kW	x	x	
Rate B kWh	x	x	
Rate B Maximum kW	x	x	
Rate C kWh	x	x	
Rate C Maximum kW	x	x	
Rate D kWh	x	x	
Rate D Maximum kW	x	x	

**Attachment 2
 Meter Display Items (cont.)**

Display Item	Normal Mode	Alternate Mode	Test Mode
Minimum Requirements for Delivered kWh (cont.)			
Total kWh	x	x	x
Wh per disk revolution (Kh)		x	
Wh per pulse (Ke)		x	
Minimum Requirements for Test Mode			
Present Interval Demand—kW			x
Pulse count			x
Time left in subinterval			x
Total kWh			x
Additional requirements for Received kWh (if specified)			
Previous Billing Total Received kWh		x	
Previous Season Total Received kWh		x	
Total Received kWh	x	x	
Additional requirements for kVARh (if specified)			
Maximum Delivered kVAR		x	
Maximum Received kVAR		x	
Previous Billing Maximum Delivered kVAR		x	
Previous Billing Maximum Received kVAR		x	
Previous Billing Total Delivered kVARh		x	
Previous Billing Total Received kVARh		x	
Previous Season Maximum Delivered kVAR		x	
Previous Season Maximum Received kVAR		x	
Previous Season Total Delivered kVARh		x	
Previous Season Total Received kVARh		x	
Total Delivered kVARh		x	
Total Received kVARh		x	
Previous Billing Maximum Delivered kVA		x	
Previous Billing Maximum Received kVA		x	
Previous Billing Total Delivered kVAh		x	
Previous Billing Total Received kVAh		x	
Previous Season Maximum Delivered kVA		x	
Previous Season Maximum Received kVA		x	

Attachment 2
Meter Display Items (cont.)

Additional requirements for kVAh (cont.)			
Previous Season Total Delivered kVAh		x	
Previous Season Total Received kVAh		x	
Total Delivered kVAh		x	
Total Received kVAh		x	
Additional requirements for Power Factor (if specified)			
Quadrant 1 Average Power Factor		x	
Quadrant 2 Average Power Factor		x	
Quadrant 3 Average Power Factor		x	
Quadrant 4 Average Power Factor		x	
Total Average Power Factor Delivered		x	
Total Average Power Factor Received		x	

EXHIBIT 2 TO PART D

**ISO SPECIFICATION
FOR CERTIFICATION OF OIL-FILLED,
WOUND INSTRUMENT TRANSFORMERS
FOR REVENUE METERING**

1 Purpose

This Exhibit specifies the technical requirements for reliable high-accuracy Current Transformers (CT) and Voltage Transformers (VT) to be used for revenue quality metering on the ISO Controlled Grid.

2 Scope

2.1 This Exhibit applies only to the following:

- Oil-filled Single-Phase CTs - 35kV-230kV.
- Oil-filled Single-Phase VTs - 35kV-230kV.
- Oil-filled Single-Phase Combination Current/Voltage Transformers - 35kV-230kV.

2.2 This Exhibit applies only to the following Oil-filled Wound Devices, which are VTs < 35kv.

VTs > 230kv must be individually specified in accordance with the engineered installations.

3 Standards

All instrument transformers covered by this Exhibit shall be designed, manufactured, tested and supplied in accordance with the applicable standards referred to in Appendix J to the ISO Tariff.

4 Definitions

“Hermetically Sealed” means completely sealed by fusion, soldering, etc., so as to keep air or gas from getting in or out (i.e. airtight).

“Metering Unit” means one or more Voltage element(s) and one or more Current element(s) contained in one common housing.

“BIL Rating” means basic lightning impulse insulation level.

“Burden Rating” means the total impedance (in ohms) that can be connected to the secondary circuit(s) of an instrument transformer while still maintaining metering accuracy of plus-or-minus 0.3%

5 Specifications

5.1 General

All instrument transformers covered by this Exhibit shall be hermetically sealed, oil-filled type and have a minimum BIL Rating appropriate for the designated nominal System voltage:

- 60 - 69 kV – 350 kV BIL
- 115 kV – 550 kV BIL

- 230 kV – 900 kV BIL

5.2 Current Transformers

5.2.1 Current Transformer windings (typical configurations) shall be either:

- (a) a single primary winding and single secondary winding with dual ratio tap;
- (b) a dual primary winding and a single ratio tap;
- (c) a single primary winding and one or more secondary windings with dual ratio tap(s); or
- (d) other combinations as available and approved by the ISO.

5.2.2 Rated primary current

The rated primary current must be as specified by the ISO Metered Entity.

5.2.3 Rated secondary current

The rated secondary current must be 5 amperes @ rated primary current.

5.2.4 Accuracy and burden

All current transformers shall have an accuracy and burden of:

- (a) standard – plus-or-minus 0.3% @ B0.1 - 1.8 ohms, 10% - 100% rated current; or
- (b) optional – plus-or-minus 0.15 % @ B0.1 - 1.8 ohms, 5% - 100 % rated current.

5.2.5 Continuous current rating factor

All current transformers shall have a continuous current rating factor of:

- (a) standard – 1.5 @ 30 degrees C Ambient; or
- (b) optional – 1.0 @ 30 degrees C Ambient.

5.2.6 Short time thermal current rating

The short time thermal current rating varies with transformer rating as follows:

25/50: 5 ratio, 4 kA RMS to 1500/3000:5 ratio, 120 kA RMS.

5.2.7 Mechanical short time current rating

The mechanical short time current rating varies with transformer rating as follows:

25/50:5 ratio, 3 kA RMS to 1500/3000:5 ratio, 90 kA RMS.

5.3 Voltage Transformers

- 5.3.1** Transformer windings shall consist of a single primary winding and one or more tapped secondary windings.
- 5.3.2** Rated primary voltage, as specified by the ISO Metered Entity, must be 34,500 volts through 138,000 volts, L-N.
- 5.3.3** Rated secondary voltage must typically be 115/69 volts.
- 5.3.4** The ratio of primary to secondary windings must be 300/500:1 through 1200/2000:1.

5.3.5 Accuracy and burden

All voltage transformers shall have accuracy and burden of:

- (a) standard – plus-or-minus 0.3% through B. ZZ @ 90% through 110% of nominal voltage;
or
- (b) optional – plus-or-minus 0.15% through B. Y 90% through 110% of nominal voltage.

5.3.6 Thermal burden rating

All voltage transformers shall have a thermal burden rating of:

- (a) 34.5 kV – 2500 VA, 60 hertz;
- (b) 60 kV & 69 kV – 4000 VA, 60 hertz; or
- (c) 115 kV – 6000 VA, 60 hertz.

5.4 Combination Current/Voltage Transformers (Metering Units)

Combination Current/Voltage Transformers shall maintain the same electrical, accuracy and mechanical characteristics as individual CTs and VTs. Physical dimensions may vary according to design.

5.5 Grounding

The neutral terminal of the VT shall exit the tank via a 5kV insulated bushing and be grounded by means of a removable copper strap to a NEMA 2-hole pad.

5.6 Primary Terminals

The primary terminals shall be tin-plated NEMA 4-hole pads (4"x4").

5.7 Paint

Exterior metal non current-carrying surfaces shall be painted with a weather-resistant paint system consisting of one primer and two industry recognized gray finish coats. As an option, for

high-corrosion areas, special corrosion-resistant finishes (e.g. zinc-rich paint, stainless steel tank) shall be used.

5.8 Porcelain

Porcelain shall be of one-piece wet-process, glazed inside and outside. The outside color shall be in accordance with industry recognized gray glaze. The minimum creepage and strike-to-ground distances for various voltages shall be as follows:

Voltage (nominal kV)	Creepage (inches)	Strike (inches)
34.5	34	13
60 & 69	52	24
115	101	42
230	169	65
230 (1050 BIL)	214	84

5.9 Insulating Oil

The nameplate shall be of non-corroding material and shall indicate that the dielectric fluid is free of polychlorinated biphenyls by the inscription:

“CONTAINS NO PCB AT TIME OF MANUFACTURE”.

5.10 Accessories

All units shall be equipped with the following standard accessories:

- 1/2" brass ball drain valve with plug
- 1" oil filling opening with nitrogen valve
- Magnetic oil level gauge, readable from ground level
- Primary bypass protector
- Sliding CT shorting link
- Four 7/8"x 2-3/8" mounting slots
- Four 1" eyebolts on base for four-point lifting sling
- 1/4" threaded stud secondary terminals

- Two conduit boxes, each with three 1-1/2" knockout

6 Testing

The ISO Metered Entity shall ensure that, before shipment, each transformer is subjected to testing as prescribed by recognized industry standards and other tests including:

- (a) Applied voltage test for primary and secondary winding withstand to ground;
- (b) Induced voltage test for proper turn-to-turn insulation;
- (c) Accuracy test for ratio correction factor and phase-angle verification to confirm 0.3% metering accuracy per recognized industry standards;
- (d) Ratio test;
- (e) Insulation Power Factor test;
- (f) Polarity test;
- (g) Leak test to assure integrity of gaskets and seals; and
- (h) Partial Discharge Test may be done in conjunction with applied voltage testing to assure proper line-to-ground withstand.

The tests shall be submitted to the ISO on a formal certified test report.

7 Required Information

The following drawings and information shall be required:

- (a) 3 sets of drawings showing physical dimensions including mounting holes and primary CT terminal details, nameplate. The ISO Metered Entity shall ensure that it receives a schematic of connections from its supplier; and
- (b) a copy of quality controls/quality assurance (QC/QA) manuals applicable to production of the transformer(s).

PART E

TRANSFORMER AND LINE LOSS CORRECTION FACTORS

E 1 Introduction

Transformer loss correction refers to the practice of metering electrical Energy delivered at a high-voltage billing point using metering equipment connected on the low-voltage side of the delivery point. The metering equipment is provided with a means of correction that adds to, or subtracts from, the actual active and reactive metered values in proportion to losses that are occurring in the transformer.

Transformer losses are divided into two parts:

the core or iron loss (referred to as the no-load loss); and

the copper loss (referred to as the load loss).

Both the no-load loss and the load loss are further divided into Watts and Var components.

The no-load (iron) loss is composed mostly of eddy current and hysteresis losses in the core. No-load loss varies in proportion to applied voltage and is present with or without load applied. Dielectric losses and copper loss due to exciting current are also present, but are generally small enough to be neglected.

The load (copper) watt loss ($I^2 +$ stray loss) is primarily due to the resistance of conductors and essentially varies as the square of the load current. The Var component of transformer load loss is caused by the leakage reactance between windings and varies as the square of the load current.

Line losses are considered to be resistive and have I^2R losses. The lengths, spacings and configurations of lines are usually such that inductive and capacitive effects can be ignored. If line losses are to be compensated, they are included as part of the transformer load losses (Watts copper).

The coefficients, which are calculated at the calibration point of the meter, are entered into the meter as Percent Loss Watts Copper (%LWCU), Percent Loss Watts Iron (%LWFE), Percent Loss Vars Copper (%LVCU), and Percent Loss Vars Iron (%LVFE).

Percent losses are losses expressed as a percent of the full load on a meter.

The formulas used to determine the compensation values at a particular operating point are:

$$\text{WATTS} \quad \text{Measured Voltage}^2 \quad \text{Measured Current}^2$$
$$\text{Compensation} = \frac{\text{Value}}{\text{Calibration Point Voltage}^2} * \%LWFE + \frac{\text{Value}}{\text{Calibration Point Current}^2} * \%LWCU$$

$$\text{Compensation} = \frac{\text{Vars}}{\text{Value}} \frac{\text{Measured Voltage}^4}{\text{Calibration Point Voltage}^4} * \%LVFE + \frac{\text{Measured Current}^2}{\text{Calibration Point Current}^2} * \%LVCU$$

E 2 Calculating Transformer Loss Constants

Transformer Loss correction calculations with electronic meters are accomplished internally with firmware. Various setting information and test data is required to calculate the four values which are to be programmed into the meter.

The following information is required about meter installations:

the transformer high voltage (HV) voltage rating

the transformer kVa rating

the transformer high voltage (HV) tap settings

the transformer low voltage (LV) tap settings

the transformer connection (wye or delta)

the transformer phases (1 or 3)

the voltage transformer (VT) ratio

the current transformer (CT) ratio

the number of meter elements

The following data from a transformer test report is required:

no-load (iron) loss

full-load (copper) loss

percent impedance

percent excitation current

The test data required may be obtained from the following sources:

the manufacturer's test report

a test completed by a utility or independent electrical testing company

If the transformer bank is used to deliver power to more than one entity (that is, it is a joint use transformer bank) additional data is required, including the:

maximum available kVa from the transformer bank

contracted amount of load to be compensated in kW

contractual power factor amount to be used in calculations

E 3 Calculating Line Loss Constants

Line Loss correction calculations with electronic meters are accomplished internally with firmware. Various information about the radial line is required to calculate the value which is programmed into the meter. The resistance of the conductors are used to calculate a value which is added to the Watts copper loss value which is programmed into the meter. It is not practical to compensate for line losses in a network connected line, only radial lines.

The following information is required about the transmission line:

the transmission line type

the ohms per mile

the length in miles of each type of line

E 4 Applications

Joint Use Transformers

Where a transformer bank is used to deliver power to more than one entity (that is, a joint use transformer bank), no-load iron losses are adjusted by the transformer percent use. This percent use is determined by dividing a negotiated contract kW load (*Contract kW*) at a negotiated power factor (*% Power Factor*) by the maximum available kVa from the transformer bank (*Max. Available kVa*).

$$\text{Percent Use} = \frac{\text{Contract kW} / \% \text{ Power Factor}}{\text{Max. Available kVa}}$$

Switched Lines

Line Loss correction for radial lines which are switched, must be based on a negotiated average resistance based on the typical operating characteristics.

Transformer Load Tap Changer

Transformers equipped with a load tap changer (i.e., which has the capability to change transformer voltage tap positions or settings under Load) for regulating voltage, must have the corrections calculated at the median tap voltage. Differences in the corrections

must be minimal and must even out over time as the bank operates above and below the median tap voltage.

E 5 Worksheets

A pro forma Transformer and Line Loss Correction Worksheet which can be used to perform the above calculation is attached to this Part. Instructions for completing the worksheet are as follows:

Complete the Name, Delivery, Location and Revision Date fields using the ISO Metered Entity's name, operating name, city, state, and the date of the calculation.

Enter Transformer High Voltage (HV) winding rated voltage, this is the voltage at which the transformer tests were performed.

Enter the HV and Low Voltage (LV) transformer tap settings.

Enter 'Y' or 'D' to indicate the secondary winding connection of either wye or delta.

Enter '1' to indicate that the transformer bank is comprised of single phase units or '3' to indicate the bank is comprised of three phase units.

Enter '2' or '3' to indicate the number of elements in the meter.

Enter the VT and CT ratios of the instrument transformers used in the metering.

Enter 'Y' or 'N' to indicate if the transformer bank is utilized by more than one entity.

Enter the negotiated contract and power factor for the joint use portion of the transformer (if any).

If compensation coefficients are required at a calibration point other than five amps, enter the new value.

Space is provided to make comments about the calculation or delivery configuration.

Enter the manufacturer and serial number of the transformer(s).

Enter the kVa rating of each bank. For multiple rated banks, the base kVa should be used. Enter the test data collected at base kVa.

Enter the no-load losses in Watts from the test data.

Enter the load losses in Watts from the test data.

Enter the impedance from the test data.

Enter the Exciting current from the test data.

If the maximum available kVa from the transformer bank is more than the rated kVa, this value can be entered manually. An example may be for a triple rated transformer that has fans with a rating which is more than the base kVa. This value only affects the percent use calculation.

Enter the line type for each type of line to be compensated.

Enter the resistance in ohms per mile of each type of line to be compensated.

Enter the total length in miles of each type of line to be compensated.

E 6 Reference Materials

The following additional references may be referred to for assistance when calculating the correction factors referred to in this Part.

Handbook For Electricity Metering, Ninth Edition. Edison Electric Institute. Washington, D.C.

Eastern Specialty Company Bulletin No. 63.

American National Standard Institute. Test Code for Distribution, Power and Regulating Transformers.

System Loss Compensation, Schlumberger Industries, Quantum Multifunction Meter Hardware Instruction Manual 1610, November 1993.

Transformer Loss Calculation Method, Process System Manual, Appendix E.

Transformer and Line Loss Correction Worksheet (Example)
TRANSFORMER AND LINE LOSS CORRECTION

Name: Acme Power Company
 Delivery: Delivery Number 5
 Location: Surf Beach, CA
 Rev. Date: 5/6/97

HV Rated Voltage:	110000 V	VT Ratio:	60:1
HV Tap:	101200 V	CT Ratio:	600:5
LV Tap:	13090 V	Joint Use (Y/N):	N
Trf. Conn. (Y/D):	Y	Metering Trf. Use:	100 %
Trf. Phase (1 or 3)	3	Contract kW:	10,000 kW
# Meter Elem.:	3	Power Factor:	95 %

Compensation Values (@ 5A F.L.)		Compensation Values at: 10 A	
Watt Fe Loss:	0.16 %	Watt Fe Loss:	.08 %
Watt Cu Loss:	0.53 %	Watt Cu Loss:	1.06 %
Watt Tot. Loss:	0.69 %	Watt Tot. Loss:	1.14 %
Var Fe Loss:	0.31 %	Var Fe Loss:	0.16 %
Var Cu Loss:	10.96 %	Var Cu Loss:	21.92 %
Var Tot. Loss:	11.27 %	Var Tot. Loss:	22.08 %

Comments:

TRANSFORMER DATA

Serial Number	KVa Rating	No Load (Fe) Loss	Load (Cu) Loss	(Z) Impedance	(IE) Exciting Current
ABB 1000001	12000	22200 w	51360 w	8.84 %	0.45 %

Total kVa rating:	12000		Max Available kVa:	12000
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LINE DATA

	Resistance	Length
#1 Line Type:	Ohms/mile	miles
#2 Line Type:	Ohms/mile	miles
#3 Line Type:	Ohms/mile	miles
#4 Line Type:	Ohms/mile	miles
#5 Line Type:	Ohms/mile	miles
#6 Line Type:	Ohms/mile	miles

Transformer and Line Loss Correction Worksheet (Example, continued)
TRANSFORMER AND LINE LOSS CORRECTION

Name: ACME Power Company
 Delivery: Delivery Number 5
 Location: Surf Beach, CA
 Rev. Date: 5/6/97

HV Rated Voltage:	110000 V	VT Ratio:	60:1
HV Tap:	101200 V	CT Ratio:	600:5
LV Tap:	13090 V	Joint Use (Y/N):	N
Trf. Conn. (Y/D):	Y	Metering Trf. Use:	100 %
Trf. Phase (1 or 3)	3	Contract kW:	10,000 kW
# Meter Elem.:	3	Power Factor:	95 %

TRANSFORMERS

Serial Number	kVa
ABB 1000001	12000

TRANSFORMER LOSS COMPENSATION TEST POINTS FOR WATTHOURS

SERIES TEST

Test Load	% Iron	% Copper	% Total
Light	1.60	0.05	1.65
Full	0.16	0.53	0.69
0.5 P.F.	0.32	1.06	1.38

TRANSFORMER LOSS COMPENSATION TEST POINTS FOR VARHOURS

SERIES TEST

Test Load	% Iron	% Copper	% Total
Light	3.10	1.10	4.20
Full	0.31	10.96	11.27
0.5 P.F.	0.62	21.92	22.54

Pro Forma Transformer and Line Loss Correction Worksheet
TRANSFORMER AND LINE LOSS CORRECTION

Name:
 Delivery:
 Location:
 Rev. Date:

HV Rated Voltage:	V	VT Ratio:	:1
HV Tap:	V	CT Ratio:	:5
LV Tap:	V	Joint Use (Y/N):	
Trf. Conn. (Y/D):		Metering Trf. Use:	100 %
Trf. Phase (1 or 3)		Contract kW:	kW
# Meter Elem.:		Power Factor:	%

Compensation Values (@ 5A F.L.)		Compensation Values 10 A at:	
Watt Fe Loss:	%	Watt Fe Loss:	%
Watt Cu Loss:	%	Watt Cu Loss:	%
Watt Tot. Loss:	%	Watt Tot. Loss:	%
Var Fe Loss:	%	Var Fe Loss:	%
Var Cu Loss:	%	Var Cu Loss:	%
Var Tot. Loss:	%	Var Tot. Loss:	%

Comments:

TRANSFORMER DATA

Serial Number	KVa Rating	No Load (Fe) Loss	Load (Cu) Loss	(Z) Impedance	(IE) Exciting Current

Total kVa rating:	Max Available kVa:
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LINE DATA

	Resistance	Length
#1 Line Type:	Ohms/mile	miles
#2 Line Type:	Ohms/mile	miles
#3 Line Type:	Ohms/mile	miles
#4 Line Type:	Ohms/mile	miles
#5 Line Type:	Ohms/mile	miles
#6 Line Type:	Ohms/mile	miles

Pro Forma Transformer and Line Loss Correction Worksheet (continued)
TRANSFORMER AND LINE LOSS COMPENSATION

Name:
 Delivery:
 Location:
 Rev. Date:

HV Rated Voltage:	V	VT Ratio:	:1
HV Tap:	V	CT Ratio:	:5
LV Tap:	V	Joint Use (Y/N):	
Trf. Conn. (Y/D):		Metering Trf. Use:	100 %
Trf. Phase (1 or 3)		Contract kW:	kW
# Meter Elem.:		Power Factor:	%

TRANSFORMERS

Serial Number	kVa
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TRANSFORMER LOSS COMPENSATION TEST POINTS FOR WATTHOURS

SERIES TEST

Test Load	% Iron	% Copper	% Total
Full			
0.5 P.F.			
Light			

TRANSFORMER LOSS COMPENSATION TEST POINTS FOR VARHOURS

SERIES TEST

Test Load	% Iron	% Copper	% Total
Full			
0.5 P.F.			
Light			

PART F

**INSTRUMENT TRANSFORMER RATIO AND CABLE LOSS
CORRECTION FACTORS**

Background

All current transformers (CTs) and voltage transformers (VTs) (collectively, instrument transformers) have inherent errors due to their design and the physical properties of the materials used in their construction. These errors are manifested as a magnitude and phase angle difference between the "ideal" nameplate ratio and the waveform actually present on the secondary of the transformer. The terms used to denote these errors are Ratio Correction Factor (RCF) and Phase Angle Correction Factor (PACF).

The burden (load) connected to instrument transformer secondaries has an effect on the RCF and PACF of the units. All wiring and instrumentation of any kind is part of the burden. On a CT, the burden is designated in ohms and is represented by a number ranging from B-0.1 through B-1.8. On a VT, burden is measured in volt-amps and indicated by an alpha character, such as W, X, M, Y, Z or ZZ. The magnitude of these burdens must be known and kept within specified limits or additional errors will occur in the metering.

Significant impedance in the leads between the VTs and the meter can be another source of error, where a voltage drop in the leads is caused by the load of the meter and any other connected devices between the VTs and the meter. Conductors which are too small or too long can cause metering error.

Correction when the Burden Rating is exceeded

Where the connected burden of a metering circuit exceeds the burden rating of a CT or VT or if an existing instrument transformer does not meet minimum ISO accuracy requirements, then one of the actions listed below must to be taken:

- i. The preferred action is to correct the problem by either replacing the instrument transformer(s) with higher burden rated revenue class units or reducing the burden on the circuit to comply with the name plate of existing instrument transformer(s).
- ii. An acceptable action is to apply ISO approved correction factors to the meter to adjust the meter's registration to compensate for inaccuracies.

The ISO Metered Entity will be responsible for properly calculating and applying the CT/VT and cable loss correction factors to its meter to adjust for inaccuracies in the metering circuit. ISO approved algorithms and spreadsheets for calculating correction factors are included in this Part.

CT Ratio Correction Factor

Current transformers are usually tested by the manufacturer for the value of RCF and phase angle at both 5 and 0.5 amp secondary currents. The values for each CT in an installation would be averaged together to determine the CT Ratio Correction Factor (RCFI) and CT Phase Angle (b). If the current transformers used are revenue metering with an accuracy class of 0.3 % and are operated at or below their rated burden, then the correction factors may be disregarded.

VT Ratio Correction Factor

Voltage transformers are usually tested by the manufacturer for the value of RCF and phase angle at rated voltage. The values for each VT in an installation would be averaged together to determine the VT Ratio Correction Factor (RCFE) and VT Phase Angle (g). If the voltage transformers used are revenue metering with an accuracy class of 0.3 % and are operated at or below their rated burden, then the correction factors may be disregarded.

Cable Loss Correction Factor

The secondary voltage cables at an installation can be tested to determine the losses and phase angle of each. These values would then be averaged together to get the Cable Loss Correction Factor (CLCF) and the Phase Angle (a) for the installation. If the calculated connected burden of each phase do not exceed the VT burden rating, then the correction factors may be disregarded.

Final Correction Factor

The PACF for an installation is determined by the following formula:

$$PACF = \frac{\cos(Q + b - a - g)}{\cos Q}$$

Where $\cos Q$ is the secondary apparent power factor.

The Final Correction Factor (FCF) can then be determined as follows:

$$FCF = RCFI * RCFE * CLCF * PACF$$

The Percent Error is the amount of error caused by the instrument transformers and cable loss, it is calculated as follows:

$$\text{Percent Error} = (1-FCF)*(100)$$

The Percent Meter Adjustment is the adjustment to the meter required to compensate for the Percent Error, it is calculated as follows:

$$\text{Percent Adjustment Factor} = (FCF-1)*(100)$$

The FCF is applied to the calibration of the meter, usually through adjustment of the calibration potentiometer or through a change in the programmed calibration values. After an adjustment to the meter is made, the meter should be tested at all test points to show that the meter is within calibration limits with the calibration values applied. A FCF which results in a correction of less than 0.6% can be disregarded since this is less than the required combined accuracy of the instrument transformers. However, if any correction factor (full load, light load or power factor) results in a correction of more than 0.6%, they should all be applied.

Applications

Typical Installation

The preferred meter installation would utilize revenue metering class instrument transformers (0.3 %) operated at or below rated burden. If this is not the case, one or more of the following actions may be used to correct the problem:

Replace instrument transformers with higher burden rated units.

Reduce the burden on the circuit to comply with the existing rated burden.

Apply correction factors to the meter to compensate for inaccuracies.

Paralleling CTs

In normal revenue metering, current transformers would not be paralleled, but there are some applications where paralleling is done because the cost of the installation is reduced and the possibility of reduced meter accuracy is acceptable. A typical installation of this type would be to meter the net output of a generating station on a single meter rather than metering gross generator output and auxiliary power separately. In these type of installations additional rules apply:

All of the transformers must have the same nominal ratio regardless of the ratings of the circuits in which they are connected.

All transformers which have their secondaries paralleled must be connected in the same phase of the primary circuits.

The secondaries must be paralleled at the meter and not at the current transformers.

There should only be one ground on the secondaries of all transformers. This should be at their common point at the meter. Each utility may use their established grounding procedures.

Modern current transformers with low exciting currents and, therefore, little shunting effect when one or more current transformers are "floating" at no load should be used. Three or more "floating" current transformers might have an effect that should be investigated.

The secondary circuits must be so designed that the maximum possible burden on any transformer will not exceed its rating. The burden should be kept as low as possible as its effects are increased in direct proportion to the square of the total secondary current.

A common voltage and frequency must be available for the meter.

If adjustments are made at the meter to compensate for ratio and phase angle errors, the ratio and phase angle error corrections used must represent the entire combination of transformers as a unit.

The watt-hour meter must be able to carry, without overload errors, the combined currents from all the transformers to which it is connected.

While servicing meters and equipment on parallel CT secondaries, all CTs must be by-passed (shorted). When work is completed all by-passes must be removed.

Worksheets

A worksheet which can be used to perform the above calculations is attached to this Part. Instructions for completing the worksheet follow:

Complete the Name, Delivery and Location fields using the ISO Metered Entity's name, the operating name of the delivery, and the city and state for the location.

Enter the values of RCF and phase angle as tested at full load and light load for each CT in the circuit. Record the manufacturer and serial number of each transformer.

Enter the values of RCF and phase angle as tested at rated voltage for each VT in the circuit. Record the manufacturer and serial number of each transformer.

Enter the values of the Cable Loss Correction Factor and Phase Angle for the secondary voltage cables.

The worksheet will calculate the Final Correction Factors, Percent Errors and Percent Adjustment Factors to be applied to the meter calibration.

Reference Materials

The following additional reference may be referred to for assistance when calculating the correction factors referred to in this Part.

Handbook For Electricity Metering, Ninth Edition. Edison Electric Institute. Washington, D.C.

CT/VT Ratio and Cable Loss Correction Worksheet (Example)

Name:

Delivery:

Location:

Full Load	Light Load
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CT Test Data:

Phase 'A' CT Mfr. & Serial Number:

Ratio Correction Factor (RCF ^L)	1.0003	1.0002
Phase Angle (β) (minutes)	-0.3	2.2

Phase 'B' CT Mfr. & Serial Number:

Ratio Correction Factor (RCF ^L)	1.0004	1.0029
Phase Angle (β) (minutes)	-0.4	2.2

Phase 'C' CT Mfr. & Serial Number:

Ratio Correction Factor (RCF ^L)	1.0019	1.0028
Phase Angle (β) (minutes)	-0.3	3.1

Average of CT's Mfr. & Serial Number:

Ratio Correction Factor (RCF ^L)	1.0009	1.0020
Phase Angle (β) (minutes)	-0.3	2.5

VT Test Data:

Phase 'A' VT Mfr. & Serial Number:

Ratio Correction Factor (RCF ^E)	0.9997
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Phase Angle (γ) (minutes)	1.5
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Phase 'B' VT Mfr. & Serial Number:

Ratio Correction Factor (RCF ^E)	0.9996
Phase Angle (γ) (minutes)	1.5

Phase 'C' VT Mfr. & Serial Number:

Ratio Correction Factor (RCF ^E)	0.9997
Phase Angle (γ) (minutes)	1.7

Average of VT's Mfr. & Serial Number:

Ratio Correction Factor (RCF ^E)	0.9997
Phase Angle (γ) (minutes)	1.6

Cable Loss Test Data:

Phase 'A'

Ratio Correction Factor (CLCF)	0.9969
Phase Angle (α) (minutes)	4.3

Phase 'B'

Ratio Correction Factor (CLCF)	0.9949
Phase Angle (α) (minutes)	4.2

Phase 'C'

Ratio Correction Factor (CLCF)	0.9959
Phase Angle (α) (minutes)	4.7

Average Cable Loss Data

Ratio Correction Factor (CLCF)	0.9959
Phase Angle (α) (minutes)	4.4

Correction Factors:

Full Load

Power Factor

Light Load

	Full Load	Power Factor	Light Load
Avg. Combined Corr. Factor	0.9964	0.9964	0.9975
Phase Ang Corr Factor (PACF)	1.0003	1.0032	1.0001
Final Correction Factor (FCF)	0.9967	0.9996	0.9977
Percent Error	+ 0.33	+ 0.04	+ 0.23
Percent Meter Adjustment	- 0.33	- 0.04	- 0.23

CT/VT Ratio and Cable Loss Correction Worksheet

Name:

Delivery:

Location:

Full Load	Light Load
-----------	------------

CT Test Data:

Phase 'A' CT Mfr. & Serial Number:

Ratio Correction Factor (RCF ^I)		
Phase Angle (β) (minutes)		

Phase 'B' CT Mfr. & Serial Number:

Ratio Correction Factor (RCF ^I)		
Phase Angle (β) (minutes)		

Phase 'C' CT Mfr. & Serial Number:

Ratio Correction Factor (RCF ^I)		
Phase Angle (β) (minutes)		

Average of CT's Mfr. & Serial Number:

Ratio Correction Factor (RCF ^I)		
Phase Angle (β) (minutes)		

VT Test Data:

Phase 'A' VT Mfr. & Serial Number:

Ratio Correction Factor (RCF ^E)	
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Phase Angle (γ) (minutes)	
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Phase 'B' VT

Mfr. & Serial Number:

Ratio Correction Factor (RCF ^E)	
Phase Angle (γ) (minutes)	

Phase 'C' VT

Mfr. & Serial Number:

Ratio Correction Factor (RCF ^E)	
Phase Angle (γ) (minutes)	

Average of VT's

Mfr. & Serial Number:

Ratio Correction Factor (RCF ^E)	
Phase Angle (γ) (minutes)	

Cable Loss Test Data:

Phase 'A'

Ratio Correction Factor (CLCF)	
Phase Angle (α) (minutes)	

Phase 'B'

Ratio Correction Factor (CLCF)	
Phase Angle (α) (minutes)	

Phase 'C'

Ratio Correction Factor (CLCF)	
Phase Angle (α) (minutes)	

Average Cable Loss Data

Ratio Correction Factor (CLCF)	
Phase Angle (α) (minutes)	

Correction Factors:

Full Load

Power Factor

Light Load

Avg. Combined Corr. Factor			
Phase Ang Corr Factor (PACF)			
Final Correction Factor (FCF)			
Percent Error			
Percent Meter Adjustment			

PART G

**ISO DATA VALIDATION, ESTIMATION
AND EDITING PROCEDURES**

This Part is provided for information purposes only, it gives an overview of the procedures that the ISO will use to validate, edit and estimate Meter Data received from ISO Metered Entities and, where an exemption applies, Meter Data received from Scheduling Coordinator Metered Entities.

G 1 Validation

G 1.1 Timing of Data Validation

Meter Data will be remotely retrieved via WEnet from ISO Metered Entities by MDAS on a daily basis. Validation will be performed on the new Meter Data as it is retrieved from the meter or Compatible Meter Data Server in order to detect:

missing data;

data that could be invalid based upon status information returned from the meter; or

meter hardware or communication failure.

Additional validation will be performed on a daily basis to verify data against load patterns, check meters, schedules, MDAS load interval data and data obtained by SCADA.

G 1.2 Data Validation Conditions

MDAS will detect the following conditions so that erroneous data will not be used for Settlement or billing purposes:

G 1.2.1 Validation of metering/communications hardware:

meter hardware/firmware failures;

metering CT/VT failures (for example, losing one phase voltage input to the meter);

communication errors;

data which is recorded during meter tests;

mismatches between the meter configuration and host system master files;

meter changeouts (including changing CT/VT ratios);

gaps in data;

overflow of data within an interval;

ROM/RAM errors reported by the meter; and

alarms/phase errors reported by the meter.

G 1.2.2 Validation of MDAS load Interval Data characteristics:

data which exceeds a defined tolerance between main and check meters;

data which exceeds a defined tolerance between metering and SCADA data;

load factor limits;

power factor limits; and

for End-Users, validation of load patterns against historical load shapes.

G 1.3 Validation Criteria

Validation criteria will be defined by the ISO for each channel of MDAS load interval data (kW/kVar/kVa/Volts, etc.) depending on the load characteristics for each meter location and the type of data being recorded.

For loads that do not change significantly over time or change in a predictable manner, percentage changes between intervals will be used.

For loads that switch from no-load to load and for reactive power where capacitors may be switched to control power factors, validation will be based upon historical data for that meter location. If no historical data is available, data such as the rating of transformers or the maximum output from a Generator will be used to set maximum limits on interval data.

Validation will be based upon reasonable criteria that can detect both hardware and operational problems with a high degree of confidence but will be set so as to avoid unnecessary rejection of data.

G 1.4 Validation for Stated Criteria

Data validation will be performed only for the validation criteria that has been entered for each meter channel of data. For example, the number of intervals of zero Energy recorded by the meter for the channel indicated will be validated only when a non-zero value is entered for this criteria.

Additional validation will be performed on a daily basis to verify data which is based upon load patterns, comparisons to check meters, schedules, MDAS load profiles or data obtained by SCADA.

G 1.5 Validation Failure

Data that fails validation will be flagged with the reason for the failure, where applicable. Data that fails checks such as load factor limits or comparisons of a MDAS load profile to the previous day, check meter or other load shape will be identified so that manual intervention can be used to estimate the correct values in order to edit the data or to manually accept the data.

G 1.6 Validation Criteria

G 1.6.1 Time of Application of Criteria

Validation Criteria	Hourly	Daily
Meter Readings vs. MDAS load profile (Energy Tolerance)		Yes
Intervals Found vs. Intervals Expected		Yes
Time Tolerance Between MDAS and Meter	Yes	Yes
Number of Power Outage Intervals		Yes
Missing Intervals (Gap In Data)		Yes
High/Low Limit Check On Interval Demand	Yes	Yes
High/Low Limit Check on Energy		Yes
CRC/ROM/RAM Checksum Error	Yes	Yes
Meter Clock Error	Yes	Yes
Hardware Reset Occurred	Yes	Yes
Watchdog Timeout	Yes	Yes
Time Reset Occurred	Yes	Yes
Data Overflow In Interval	Yes	Yes
Parity Error (Reported By Meter)	Yes	Yes
Alarms (From Meter)	Yes	Yes
Load Factor Limit		Yes
Power Factor Limit		Yes
Main vs. Check Meter Tolerance		Yes
Actual vs Scheduled Profile		Yes
Actual vs SCADA Data		Yes
Comparison Of Current Day To Previous Day		Yes
Percent Change Between Intervals		Yes

G 1.6.2 Validation Criteria

(a) Meter Reading vs. MDAS load Interval Data (Energy Tolerance)

Meter readings will be obtained from ISO approved meters on a daily basis in order to validate interval Energy measurements

obtained from the MDAS approved meters data and Energy from the meter readings. This Energy tolerance check will be used to detect meter changeouts or changes in metering CT/PT ratios that have not been reflected in the MDAS master files (meter configuration files). A "tolerance type" parameter will be set in the MDAS system parameter to define the type of check to be performed.

The types of check that will be used will include the following (the constant used to convert the meter readings to kWh):

ID	Term	Description
M	Multiplier	Allows a percentage of the meter multiplier difference between the meter reading the recorded interval total energy.
P	Percent	Allows a percentage of the metered total energy difference between the metered total energy and the recorded total energy. The percent of allowed difference will be defined by the ISO on an individual meter channel basis.
Q	Same as Percent	Based on 30 days of data. If the data relates to a period less than 30 days then the total usage will be projected to 30 days as follows: Projected Usage=Total Usage * (30/Total Days)
D	Dual Check	Percent Method (P) is the primary check. If it fails, then the Multiplier Method (M) is used.
E	Dual Method	Percent Method (Q) is the primary check. If it fails, then the Multiplier Method (M) is used.
N	None	No tolerance check

(b) Intervals Found vs Intervals Expected

MDAS will calculate the expected number of time intervals between the start and stop time of the MDAS load profile data file and compare that number against the actual number of time intervals found in the MDAS data file. The calculation used to determine the expected number of time intervals will take into account the size or duration of the actual time intervals for the particular meter/data file (e.g., 5 min, 15 min, 30 min and 60-min interval sizes).

(c) Time Tolerance Between MDAS and Meter

When MDAS retrieves data from a meter, the MDAS workstation clock will be compared against the meter's clock. MDAS will be configured to automatically update the meter clocks within certain tolerances, limits and rules including:

- i. a time tolerance parameter (in seconds) which indicates the allowable difference between the MDAS workstation clock and the meter clock (if the meter clock is within that parameter, MDAS will not update the meter clock);

- ii. an upper limit for auto timeset which is the maximum number of minutes a meter can be out of time tolerance before MDAS will perform an auto timeset;
- iii. the MDAS will not perform auto timesets across interval boundaries; and
- iv. the auto timeset feature will support DST changes and time zone differences. Since all ISO Metered Entity's meters that are polled by MDAS will be set to PST, this rule will not generally apply.

(d) Number of Power Outage Intervals

The ISO approved meter will record a time stamped event for each occurrence of a loss of AC power and a restoration of AC power. During the Meter Data retrieval process, MDAS will flag each MDAS interval between occurrences of AC power loss and AC power restoration with a power outage status bit. MDAS will sum the total number of power outages for a time frame of MDAS data and compare that value against an ISO defined Power Outage Interval Tolerance value stored in the MDAS validation parameters.

(e) Missing Intervals (Gap in Data)

The MDAS validation process will compare the stop and start times of two consecutive pulse data files for a meter and will report if a missing interval/gap exists. The MDAS automatic estimation process for "plugging" missing intervals/gaps in data is described in more detail in the Data Estimation section of this Part.

(f) High/Low Limit Check on Interval Demand

The MDAS validation process will compare the Demand High/Low Limits entered by the MDAS operator on a meter channel basis in the MDAS meter channel table against the actual Demand value collected from the meter. This comparison will be performed on an interval by interval basis. If the actual Demand value is less than the Low Limit or greater than the High Limit, the MDAS validation process fails.

(g) High/Low Limit Check on Energy

The MDAS validation process compares the Energy High/Low Limits entered by the MDAS operator on a meter channel basis in the MDAS meter channel table against the actual total Energy collected from the meter for the time period. If the actual total Energy is less than the Low Limit or greater than the High Limit, the MDAS validation process fails.

(h) CRC/ROM/RAM Checksum Error

This general meter hardware error condition can occur during an internal status check or an internal read/write function within the meter. This error code may not be standard on some meters (reference should be made to the meter's user manual). When available, this internal status information will be collected during the MDAS Meter Data retrieval process and stored for review/reporting purposes.

(i) Meter Clock Error

This meter hardware error condition can occur whenever an internal meter hardware clock error results in an invalid time, day, month, year, etc. This error code may not be standard on some meters (reference should be made to the meter's user manual). When available this interval status information is collected during the MDAS Meter Data retrieval process and stored for review/reporting purposes.

(j) Hardware Reset Occurred

This meter hardware error condition occurs whenever an internal meter hardware reset occurs. This error code may not be standard on some meters (reference should be made to the meter's user manual). When available this interval status information is collected during the MDAS Meter Data retrieval process and stored for review/reporting purposes.

(k) Watchdog Timeout

This error code may not be standard on some meters (reference should be made to the meter's user manual). When available, this feature watches for meter inactivity, indicating a possible meter failure.

(l) Time Reset Occurred

This is a meter error code that indicates that the meter time has been reset. See paragraph (c) above.

(m) Data Overflow In Interval

This error code occurs when the amount of data in an interval exceeds the memory capabilities of the meter to store the data. This alerts MDAS that there is corrupt data for the interval.

(n) Parity Error (Reported by Meter)

Parity error is another indicator of corrupted data.

(o) Alarms (From Meter)

ISO MDAS operator will evaluate all meter alarms to determine if the alarm condition creates data integrity problems that need to be investigated.

(p) Load Factor Limit

The MDAS validation process compares the daily Load Factor to the limit entered by the MDAS operator. MDAS will prompt the operator to investigate data integrity if the limit is out of tolerance.

(q) Power Factor Limit

The MDAS validation process compares the actual Power Factor to the limit entered by the MDAS operator. MDAS will prompt the operator to investigate if the limit is out of tolerance.

(r) Main vs Check Meter Tolerance

The main and check meters can be configured in MDAS to be compared on a channel by channel basis to the check meter ID, channel number, percent tolerance allowance and the type of check. Interval or daily Meter Data will be entered into the corresponding main meter MDAS meter channel table record. This information will remain constant unless:

- i. a meter changeout occurs at the site;
- ii. the percent tolerance allowance needs adjusting; and/or
- iii. the type of check is switched.

If the percentage difference between the main channel interval Demand and the check channel interval Demand exceeds the Percent Tolerance allowed, the MDAS validation will fail. If, after applying this validation test, the percentage difference between the main channel total Energy and the check channel total Energy for each Trading Day exceeds the allowed percentage, the MDAS validation will fail. In both cases, if the percentage difference is less than the Percent Tolerance allowed, the MDAS validation will be accepted.

(s) Actual vs. Scheduled Profile

Data is compared on an interval by interval basis like Main vs Check.

(t) Actual vs. SCADA Data

Data is compared on an interval by interval basis like Main vs Check.

(u) Comparison Of Current Day To Previous Day

The MDAS validation process compares the last complete day's Demand and Energy in the validation time period to one of the following parameters configured by the MDAS operator:

- i. previous day;
- ii. same day last week; or
- iii. same day last month.

Validation Failure

If the percentage difference between the Demand and Energy exceeds the tolerance setup in the MDAS validation parameters, the data subjected to the validation process fails.

(v) Percent Change Between Intervals

The MDAS validation process uses the Interval Percent Change Tolerance set by the MDAS operator on a meter channel basis in the MDAS meter channel table to compare the percentage change in the pulses for the channel between two consecutive intervals.

If the percent change exceeds the Interval Percent Change Tolerance set for that channel, the MDAS validation process fails.

G 2 Data Estimation Criteria

When interval data is missing due to there not being any response from the meter or the meter reports it as missing, MDAS will supply estimated data for the missing intervals based on the guidelines discussed below.

If a certified Check Meter is available and that data is valid, the data from the Check Meter will be used to replace the invalid or missing data from the main meter. When reading meters on a frequency basis, the point-to-point linear interpolation method will be used to estimate the current interval(s) of data. This method will only normally be used when estimating one hour or less of contiguous missing interval data when the previous and next intervals are actual values from the meter. If data is missing for an extended time period, historical data will be used as the reference date so that data can be matched to time of day and day of week.

G 2.1 Data Estimation Methods

The following data estimation methods are configurable by the MDAS operator on a meter-by-meter basis. The algorithms for each method are described below in order of precedence as implemented by the MDAS automatic estimation application software. The MDAS operators can alter this order by simply not activating a certain method. In addition, the MDAS operator can manually select each data estimation method at any time during the data analysis process.

G 2.2 Main vs Check Meter

The global primary and Check Meters can be configured in the MDAS meter channel table to be compared on a channel-by-channel basis. The Check Meter ID and channel number will be entered into the corresponding primary meter MDAS meter channel table record. This information remains constant unless a meter changeout at the site occurs. During the MDAS automatic estimation process, if missing data is encountered and actual values from a certified Check Meter are available, the values for the corresponding intervals from that Check Meter will be substituted into the data file for the primary meter. All copied intervals will be tagged as an edited interval. In order for actual values from the check meter to be deemed acceptable for use in the automatic estimation process, the values must reside in an accepted data file that passed the validation criteria referred to earlier in this Part and no error codes or alarms can be set on the interval values. Meter Data from Check Meters may only be used where Meter Data is not available from the primary meter.

G 2.3 Point-to-Point Linear Interpolation

When reading meters on a frequency basis, the Point-to-Point Linear Interpolation Algorithm described below can be used to estimate the missing intervals of data. This method will only normally be used to estimate a maximum of one hour of contiguous missing interval data when the previous and next intervals are actual values from the meter. Even though this method will not normally be used above that maximum of one hour, the MDAS allows this maximum threshold to be set by the MDAS operator on a meter-by-meter basis. The same rules for defining acceptable actual values apply as

detailed in Main vs. Check Meter description above. All estimated intervals will be tagged as an edited interval.

Point to Point Linear Interpolation Algorithm

$$\text{Estimated Interval} = \frac{\text{Next Actual} - \text{Previous Actual Interval}}{\text{Number of Missing Intervals} + 1} + \text{Previous Actual Interval}$$

G 2.4 Historical Data Estimation

Historical data estimation is the process of replacing missing or corrupt interval data in the MDAS data files. The data is replacing using historical data as a reference. There are two basic requirements when estimating data to be inserted or replaced:

the amount of data to add or replace; and

the shape or contour of the data over the time span requested.

G 2.4.1 Estimation Parameters

The following estimation parameters are required on a per meter basis:

Auto Plug (Y/N)	Controls the option to perform automatic estimation
Auto Plug Option (W/C/P/L)	Indicates where to get the reference data used in the estimation process: W - use the previous week as the reference data (all data for the week must be present). C - use the current month as reference data. P - use the previous month as reference data. L - use the current month of last year as reference data.
Reference ID	ID from which the reference data is retrieved. The contour of the data is determined from this ID. The Reference ID can be the same as the meter ID (i.e. use historical data from the same meter) or a different Reference ID.
Auto Plug Missing Days Limit	Verifies that the number of missing days of data is less than the missing day limit in order to invoke automatic estimation.

Auto Plug Reference Data % Identifies a percent adjustment for situations where there is a need to factor the reference data by a percent increase or decrease. If this value is set to "0", the adjustment is not performed.

Auto Plug Power Outage Indicates if intervals with a power outage status are to be estimated/replaced automatically.

Reference Time Span Identifies the reference time span for the historical data.

G 2.4.2 Total Data

The estimation algorithm used depends on the total amount of data to be added or replaced and the shape of that data. The MDAS operator can give the total data or that can be calculated to balance the meter usage in the file. The shape of the data is defined with the use of the reference data.

G 2.4.3 Reference Data

The reference data is based on the day of the week. All reference data is averaged and stored into a 7-day table of values for each interval. The table includes a day's worth of intervals for each day of the week (Sunday-Saturday). When the shape of a day's data is needed, this weekly table is referenced. Two data tables are set up to use in the algorithm. One stores the number of times that an interval value is needed from the reference data. While the other table maps the interval value in the reference data to the correct data in the update file. The data from the reference must be scaled up or down to match the magnitude of the data needed for the update file. This is determined by comparing the data total from the reference file with the data needed for the update file. This ratio is used when getting reference data to use for the update file.

G 2.4.4 Iterations

Iterations will be used to get the best reproduction of data in the update file. This process will attempt to get the correct shape for the data and also to get as close to the requested total data as possible by using up to ten iterations. Since MDAS data will be integer data and cannot have decimal values, the total data used will not be exactly what is requested. Definition of some of the tables and variables are:

REFTOT Total data from the reference file for the time requested.

REQTOT Total requested data.

REFADJ Adjusted total reference data.

IP() A table containing the total times that a value is used from the reference data.

NP () A table containing the data in the update file for that value in the reference data. A table mapping the reference data to the update data according to the needed ratio.

G 2.4.5 Population of Tables

The first step is to populate the tables. All intervals for the requested time are read from the reference data. These values are stored into table NP(). The number of times a value is used is stored into the table IP(). For example:

If the value 54 is needed 3 times, then $IP(54)=3$ and $NP(54)=54$

The table IP() is used to quickly add up the totals. The table NP() is modified by the ratio $REQROT/REFADJ$. For example:

If: $REQTOT=22000$

$REFTOT=44000$

Then: $REQTOT/REFTOT=0.50$

and $NP(54) = 0.50 * NP(54) = 27$

After modifying the complete NP() table, the total data is added to determine how close this total is to the requested total (REQTOT). The NP() values have to be rounded to whole numbers. This total is calculated by adding up all of the values in the NP() table multiplied by the times the value is needed (IP()). Each value used (IP(x) not zero) is multiplied by the value (NP(x)). Then each of the results is added up to a total. If the total is close enough to the requested total then the iteration process ends. After ten iterations the total will automatically be considered close enough to the requested total.

G 2.4.6 Update File

As the data is needed to insert into the update file, the reference data is read from the reference file. The mapping table (NP) modifies the value. This modified value is inserted into the update file. All intervals are inserted in this manner to complete the data estimation.

G 3 Editing

All estimated intervals will be tagged as an edited interval in MDAS. The ISO MDAS operator will notify the Metered Entity of the edited interval start and stop times, new value and technique used to estimate the data.

If estimation and editing is frequently required for the Meter Data received from a particularly metered entity, the ISO may require re-certification and or facility maintenance or repair to correct the continued provision of erroneous or missing data.

ISO TARIFF APPENDIX P
ISO Department of Market Analysis and Market Surveillance Committee

ISO TARIFF APPENDIX P

ISO Department of Market Analysis and Market Surveillance Committee

1 ISO DEPARTMENT OF MARKET ANALYSIS

1.1 Establishment

There shall be established on or before ISO Operations Date within the ISO a Department of Market Analysis that shall be responsible for the ongoing development, implementation, and execution of the ISO Market monitoring and information scheme described in this Tariff and the adherence to its objectives, as set forth in Section 38.1.

1.2 Composition

The Department of Market Analysis shall be adequately staffed by the ISO with full-time ISO staff with the experience and qualifications necessary to fulfill the functions referred to in this ISO Tariff. Such qualifications may include professional training pertinent to and experience in the operation of markets analogous to ISO Markets, in the electric power industry, and in the field of competition and antitrust law, economics and policy. The Department of Market Analysis shall be under the general management of the ISO CEO, provided that the CEO may designate another ISO officer (currently the General Counsel) for day-to-day oversight of the Department.

1.3 Accountability and Responsibilities

1.3.1 Department of Market Analysis

The Department of Market Analysis shall report to and be accountable to the ISO CEO and his or her designee on all matters pertaining to policy and other matters that may affect the effectiveness and integrity of the monitoring function, including matters pertaining to market monitoring, information development and dissemination and pertaining to generic or entity-specific investigations, corrective actions or enforcement.

1.3.2 CEO and MSC

The ISO CEO and the MSC shall each have the independent authority to refer any of the matters referred to in Section 37.3.3.1 to the ISO Governing Board for approval of recommended actions.

1.3.3 Chief Executive Officer (CEO)

1.3.3.1 The Department of Market Analysis shall report to and be accountable to the ISO CEO and his or her designee on all matters relating to administration of the Department and the internal resources and organization of the ISO in accordance with Appendix P, Section 1.3.3.2.

1.3.3.2 The ISO, through its CEO and Governing Board, shall determine that the Department of Market Analysis has adequate resources and full access to data and the full cooperation of all parts of the ISO organization in developing the database necessary for the effective functioning of the Department of Market Analysis and the fulfillment of its monitoring function.

1.3.4 Regulatory and Antitrust Enforcement Agencies

Where considered necessary and appropriate, or where so ordered by the regulatory or antitrust agency with jurisdiction over the matter in question, or by a court of competent jurisdiction, the ISO shall refer a matter to the regulatory or antitrust enforcement agency concerned, e.g., in cases of serious abuse requiring expeditious investigation or action by the agency. In all such cases of direct referral, the ISO CEO shall promptly inform the ISO Governing Board and the MSC of the fact of and the content of the referral.

1.3.5 Complaints

Any Market Participant, or any other interested entity, may at any time submit information to or make a complaint to the Department of Market Analysis concerning any matter that it believes may be relevant to the Department of Market Analysis's monitoring responsibilities. Such submissions or complaints may be made on a confidential basis in which case the Department of Market Analysis shall preserve the confidentiality thereof. The Department of Market Analysis, at its discretion, may request further information from such entity and carry out any investigation that it considers appropriate as to the concern raised. The Department of Market Analysis shall periodically make reports to the ISO CEO and ISO Governing Board on complaints received.

ISO TARIFF APPENDIX P1

ISO Department of Market Analysis

P1.1 ISO Department of Market Analysis

P1.1.1 Information Gathering and Market Monitoring Indices for Evaluation

P1.1.1.1 Information System

The Department of Market Analysis shall be responsible for developing an information system and criteria for evaluation that will permit it to effectively monitor the ISO Markets to identify and investigate abuses of that market, whether caused by exercises of market power or by other actions or inactions.

P1.1.1.2 Data Categories

To develop the information system set forth in Section P1.1.1.1, the Department of Market Analysis shall initially develop, and shall refine on the basis of experience, a detailed catalog of all the categories of data it will have the means of acquiring, and the procedures it will use (including procedures for protecting confidential data) to handle such data.

P1.1.1.3 Catalog of Market Monitoring Indices

The Department of Market Analysis shall initially develop, and shall refine on the basis of experience, a catalog of the ISO Market monitoring indices that it will use to evaluate the data so collected.

P1.1.2 Evaluation of Information

P1.1.2.1 Ongoing Evaluation

The Department of Market Analysis shall evaluate and reevaluate on an ongoing basis the data categories and market monitoring indices that it has developed under Appendix P1, Sections P1.1.1.2 and P1.1.1.3, and the information it collects and receives from various other sources, including and in particular the ISO's operation of the ISO Markets. Such ongoing evaluations shall provide the basis for its reporting and publication responsibilities as set forth in this ISO Tariff, for recommendations on proposed changes to the ISO Tariff and ISO Protocols and other potential rules affecting the ISO Markets, and for the development of criteria or standards for the initiation of proposed corrective or enforcement actions. In evaluating such information, the Department of Market Analysis may consult the MSC or such external bodies as may be appropriate.

P1.1.2.2 Submission of Evaluation Results

The final results of the Department of Market Analysis's ongoing evaluations under Appendix P1, Section P1.1.2.1 shall routinely and promptly be submitted to the ISO CEO and to the MSC for comment.

P1.1.3 Review of Rules of Conduct

The Department of Market Analysis shall review Rules of Conduct for their effectiveness and consistency with its market monitoring activities and standards. The Department of Market Analysis may at that time, and from time to time thereafter based on its experience in monitoring the ISO Markets, propose to the ISO CEO and/or the ISO Governing Board that changes be made in such Rules of Conduct.

P1.1.4 Reports and Recommendations

P1.1.4.1 ISO CEO and Governing Board

On the basis of the evaluation conducted under Appendix P1, Section P1.1.2 or the review conducted under Section 37.4.3, the Department of Market Analysis shall prepare periodic reports, as required by the ISO CEO, and specific ad hoc reports as appropriate, for the ISO CEO and ISO Governing Board on the state of competition in or the efficiency of the ISO Markets; and on its monitoring activities, the results of its evaluation and review activities, and its development and implementation of recommendations. Where appropriate, the ISO Department of Market Analysis may recommend to the ISO CEO and/or the ISO Governing Board actions to be taken, including the amendment of the ISO Tariff and ISO Protocols and corrective or enforcement action against specific entities. Such reports shall be made not less frequently than quarterly in the case of the ISO CEO and annually in the case of the ISO Governing Board and shall contain such information and be in such form as specified by such entities. Such reports shall be made public and publicized as specified by such entities except to the extent that they contain confidential or commercially sensitive information or to the extent such entities determine that effective enforcement of the monitoring function dictates otherwise.

P1.1.4.2 Regulatory Agencies

As required in the ISO Tariff or by the ISO CEO and ISO Governing Board, or as required by the regulatory agency with jurisdiction over the matters in question, the Department of Market Analysis shall prepare reports to the FERC and other regulatory agencies, which shall be reviewed and approved by the ISO CEO or his or her designee and then submitted as required. When publicly available reports are made to one regulatory agency with competent jurisdiction, such as the FERC, the Department of Market Analysis may simultaneously make such reports available to other regulatory agencies with legitimate interests in their contents, such as the Electricity Oversight Board, the California Public Utilities Commission, the California Energy Commission and/or the California Attorney General.

P1.1.4.3 ISO Market Surveillance Committee

All reports and recommendations to be made to regulatory agencies under Appendix P1, Section P1.1.4.2, unless urgency requires otherwise, shall first be submitted to the MSC for comments, which comments shall be reflected in any submittal to the ISO Governing Board seeking approval of any such reports or recommendations. All final reports made to external regulatory agencies shall be simultaneously submitted to the MSC.

P1.1.5 Market Participants

P1.1.5.1 Collection of Data

The Department of Market Analysis may request that Market Participants or other entities whose activities may affect the operation of the ISO markets submit any information or data determined by the Department of Market Analysis to be potentially relevant. This data will be subject to due safeguards to protect confidential and commercially sensitive data. Failures by Market Participants to provide such data shall be treated under Section 37. In the event of failures by other entities to provide such data, the ISO may take whatever action is available to it and appropriate for it to take, including reporting the failure to the pertinent regulatory agency, after providing such entity the opportunity to respond in writing as to the reason for the alleged failure and may include possible exclusion from the ISO Markets or termination of any relevant ISO agreements or certifications. Before any such action is taken, the ISO Participant shall be provided the opportunity to respond in writing as to the reason for the alleged failure.

P1.1.5.2 Dissemination of Data

Any Market Participant may request that the ISO provide data that the ISO has collected concerning that Market Participant; and, such data may, subject to constraints on the ISO's resources and at the ISO's sole discretion, be provided by the ISO subject to due safeguards to protect confidential and commercially sensitive data. Where such activity imposes a significant burden or expense on the ISO, the data may be provided on the condition that a reasonable contribution to the cost incurred by the ISO is made to the ISO by the requesting party.

P1.1.6 External Consulting Assistance and Expert Advice

In carrying out any of its responsibilities under this ISO Tariff, including the development of an information system, market monitoring indices and evaluation criteria, and the catalogs associated therewith, and in its analysis and ongoing evaluation of these catalogs and of the Rules of Conduct, the Department of Market Analysis may hire consulting assistance subject to the budgetary approval of the ISO CEO and may seek such expert external advice as it believes necessary.

P1.1.7 Liability for Damages

As provided in Section 14 of the ISO Tariff, the Department of Market Analysis, the MSC, the ISO CEO and other ISO staff, and the ISO Governing Board shall not be liable to any Market Participant under any circumstances whatsoever for any matter described in those sections, including but not limited to any financial loss or loss of economic advantage resulting from the performance or non-performance by such ISO entities of their functions under this ISO Tariff.

ISO TARIFF APPENDIX P2

Market Surveillance Committee

P2.2 Market Surveillance Committee

P2.2.1 Establishment

There shall be established on or before ISO Operations Date a Market Surveillance Committee (MSC), whose role it shall be to provide independent external expertise on the ISO market monitoring process and, in particular, to provide independent expert advice and recommendations to the ISO CEO and Governing Board. Members of the Committee shall not be, and shall not be understood to be, employees or agents of the ISO.

P2.2.2 Composition

P2.2.2.1 Qualifications

The MSC shall comprise a body of three or more independent and recognized experts whose combined professional expertise and experience shall encompass the following:

- (a) economics, with emphasis on antitrust, competition, and market power issues in the electricity industry;
- (b) experience in operational aspects of Generation and transmission in electricity markets;
- (c) experience in antitrust or competition law in regulated industries; and
- (d) financial expertise relevant to energy or other commodity trading.

P2.2.2.2 Criteria for Independence

Each member of the MSC must meet the following criteria for independence:

P2.2.2.2.1 no material affiliation, through employment, consulting or otherwise, with any Market Participant or Affiliate thereof consistent with the pertinent FERC Standards of Conduct; and

P2.2.2.2.2 no material financial interest in any Market Participant or Affiliate thereof consistent with the pertinent FERC Standards of Conduct.

P2.2.2.2.3 during their time on the Committee, members may not provide paid expert witness testimony or other commercial services to the ISO or to any other party in connection with any legal or regulatory proceeding relating to the ISO or any trade or other transaction involving the ISO markets (except that the Committee may consult with and make recommendations concerning the functioning of the markets to ISO Management or the ISO Governing Board in connection with legal or regulatory proceedings).

P2.2.3 Appointments to the MSC

For each position on the MSC, the ISO CEO shall conduct a thorough search and requisite due diligence to develop a nomination to the ISO Governing Board, which nomination shall be consistent with meeting the combined professional expertise and experience of the MSC set forth in Appendix P2, Section

P2.2.2.1 and with the criteria for independence set forth in Appendix P2, Section P2.2.2.2. The ISO Governing Board shall expeditiously consider such nominations. If the nomination is approved, the ISO

CEO shall appoint the candidate so nominated to the MSC. If the nomination is rejected, the ISO CEO shall expeditiously proceed to develop another nomination.

P2.2.4 Compensation and Reimbursements

Members of the MSC shall be compensated on such basis as the ISO Governing Board shall from time to time determine.

Members of the MSC shall receive prompt reimbursement for all expenses reasonably incurred in the execution of their responsibilities under this Appendix P2, Section P2.2.

P2.2.5 Liability for Damages

As provided in Section 14 of the ISO Tariff, the Department of Market Analysis, the MSC, the ISO CEO and other ISO staff, and the ISO Governing Board shall not be liable to any Market Participant under any circumstances whatsoever for any matter described in those sections, including but not limited to any financial loss or loss of economic advantage resulting from the performance or non-performance by such ISO entities of their functions under this ISO Tariff.

P2.2.6 SPECIFIC FUNCTIONS OF MARKET SURVEILLANCE COMMITTEE (MSC)

P2.2.6.1 Information Gathering and Evaluation Criteria

The MSC shall review the initial catalogs of information and data and of evaluation criteria developed by the Department of Market Analysis pursuant to Appendix P1, Section P1.1 and shall propose such changes, additions or deletions to such catalogs or items therein as it sees fit. In so doing, the MSC shall have full discretion to specify database items or evaluation criteria for inclusion in the pertinent catalog.

P2.2.6.2 Evaluation of Information

The MSC may, upon request of the Department of Market Analysis, the ISO Management or the ISO Governing Board, or on its own volition, evaluate such information or data, including as may be collected by the Department of Market Analysis on the basis of the evaluation criteria developed by the Department of Market Analysis or on such further articulated evaluation criteria developed by the MSC.

P2.2.6.3 Reports and Recommendations

P2.2.6.3.1 Required Reports

All evaluations carried out by the MSC pursuant to Appendix P2, Section P2.2.6.2, and any recommendations emanating from such evaluations, shall be embodied by the MSC in written reports to the ISO CEO and ISO Governing Board and shall be made publicly available subject to due restrictions on dissemination of confidential or commercially sensitive information. The MSC may submit any MSC report to FERC, subject to due restrictions on dissemination of confidential or commercially sensitive information.

P2.2.6.3.2 Additional Reports

The MSC may make such additional reports and recommendations as it sees fit relating to the monitoring program referred to in this ISO Tariff, the analysis of information, the evaluation criteria or any corrective or enforcement actions proposed by the Department of Market Analysis or proposed of its own volition.

P2.2.6.4 Publication of Reports and Recommendations

Upon request of the MSC, the ISO shall publish reports and recommendations of the MSC or incorporate them, if consistent, into the ISO's own reports or recommendations.

P2.2.7 IMPLEMENTATION OF RECOMMENDATIONS

P2.2.7.1 Plan and Rules of Conduct Changes

Following a recommendation of the MSC, the ISO Governing Board may make such changes as it believes are appropriate to the ISO Tariff, any ISO Protocol or Agreement, or any Rules of Conduct applicable in accordance with Sections 14.1.1 and 4.9 of this Tariff. .

P2.2.7.2 Tariff Changes

Upon recommendation of the MSC, the ISO Governing Board shall consider and may adopt proposed ISO Tariff changes in accordance with Section 14.1.1 of this Tariff.

P2.2.7.3 Sanctions and Penalties

Upon recommendation of the MSC, the ISO may impose such sanctions or penalties as it believes necessary and as are permitted under the ISO Tariff and related protocols approved by FERC; Section 37.9 or it may make any such referral to such regulatory or antitrust agency as it sees fit to recommend the imposition of sanctions and penalties.

P2.2.8 PUBLICATION OF INFORMATION

P2.2.8.1 Market Monitoring Data and Indices

The ISO Department of Market Analysis shall, pursuant to Appendix P1, Section P1.1.1, develop a catalog of data and indices. Upon approval of the ISO CEO, such catalogs shall be duly published on the ISO Home Page and disseminated to all Market Participants.

P2.2.8.2 Reports to Regulators

The ISO shall develop annual reports of market performance for delivery to FERC, and such other reports as may be required by FERC, which shall be submitted for review to the MSC. The Department of Market Analysis shall prepare and submit such reports to the ISO CEO, ISO Governing Board and to the regulatory agency concerned.

ISO TARIFF APPENDIX P

Attachment A

Conduct Warranting Mitigation

ISO Market Monitoring Plan

Market Mitigation Measures

1 PURPOSE AND OBJECTIVES

1.1 These ISO market power mitigation measures ("Mitigation Measures") are intended to provide the means for the ISO to mitigate the market effects of any conduct that would substantially distort competitive outcomes in the ISO Real Time Market while avoiding unnecessary interference with competitive price signals. These Mitigation Measures are intended to minimize interference with an open and competitive market, and thus to permit, to the maximum extent practicable, price levels to be determined by competitive forces under the prevailing market conditions. To that end, the Mitigation Measures authorize the mitigation only of specific conduct that exceeds well-defined thresholds specified below.

1.2 In addition, the ISO shall monitor the markets it administers for conduct that it determines constitutes an abuse of market power but does not trigger the thresholds specified below for the imposition of mitigation measures by the ISO. If the ISO identifies any such conduct, and in particular conduct exceeding the thresholds for presumptive market effects specified below, it shall make a filing under Section 205 of the Federal Power Act, 16 U.S.C. § 824d, with FERC, requesting authorization to apply appropriate mitigation measures. Any such filing shall identify the particular conduct the ISO believes warrants mitigation, shall propose a specific mitigation measure for the conduct, and shall set forth the ISO's justification for imposing that mitigation measure.

2 CONDUCT WARRANTING MITIGATION

2.1 Definitions

The following definitions are applicable to this Attachment A:

"Economic Market Clearing Prices" are the Market Clearing Prices for a particular resource at the location of that particular resource at the time the resource was either Scheduled or was Dispatched by the ISO. Economic Market Clearing Prices may originate from the Day-Ahead Energy market, the Hour-Ahead Energy market (when these markets are in place), or ISO real-time Imbalance Energy market. The Economic Market Clearing Price for the ISO real-time Imbalance Energy market shall be the Dispatch Interval Ex Post Price, unless the resource cannot change output level within the hour (i.e., the resource is not amenable to intra-hour real-time Dispatch instructions), or it is a System Resource. Economic Market Clearing Prices for the ISO real-time Imbalance Energy market for resources that cannot change output level within one Dispatch Interval and System Resources shall be the simple average of the relevant Dispatch Interval Ex Post Prices for each hour.

"Electric Facility" shall mean an electric resource, including a Generating Unit, System Unit, or a Participating Load.

2.2 Conduct Subject to Mitigation

Mitigation Measures may be applied: (i) to the bidding, scheduling, or operation of an "Electric Facility"; or (ii) as specified in Section 2.4 below.

2.3 Conditions for the Imposition of Mitigation Measures

2.3.1 In general, the ISO shall consider a Market Participant's conduct to be inconsistent with competitive conduct if the conduct would not be in the economic interest of the Market Participant in the absence of market power. The categories of conduct that are inconsistent with competitive conduct include, but may not be limited to, the three categories of conduct specified in Section 2.4 below.

2.4 Categories of Conduct that May Warrant Mitigation

2.4.1 The following categories of conduct, whether by a single firm or by multiple firms acting in concert, may cause a material effect on prices or generally the outcome of the ISO Real Time Market if exercised from a position of market power. Accordingly, the ISO shall monitor the ISO Markets for the following categories of conduct, and shall impose appropriate Mitigation Measures if such conduct is detected and the other applicable conditions for the imposition of Mitigation Measures are met:

- (1) Physical withholding of an Electric Facility, in whole or in part, that is, not offering to sell or schedule the output of or services provided by an Electric Facility capable of serving an ISO Market. Such withholding may include, but not be limited to: (i) falsely declaring that an Electric Facility has been forced out of service or otherwise become totally or partially unavailable, (ii) refusing to offer bids or schedules for an Electric Facility when it would be in the economic interest, absent market power, of the withholding entity to do so, (iii) declining real-time bids called upon by the ISO (unless the ISO is informed in accordance with established procedures that the relevant resource for which the bid is submitted has undergone a forced outage or derate), or (iv) operating a Generating Unit in real time to produce an output level that is less than the ISO's Dispatch instruction.
- (2) Economic withholding of an Electric Facility, that is, submitting bids for an Electric Facility that are unjustifiably high (relative to known operational characteristics and/or the known operating cost of the resource) so that: (i) the Electric Facility is not or will not be dispatched or scheduled, or (ii) the bids will set a Market Clearing Price.
- (3) Uneconomic production from an Electric Facility that is, increasing the output of an Electric Facility to levels that would otherwise be uneconomic in order to cause, and obtain benefits from, a transmission constraint.

2.4.2 Mitigation Measures may also be imposed to mitigate the market effects of a rule, standard, procedure, design feature, or known software imperfection of an ISO Market that allows a Market Participant to manipulate market prices or otherwise impair the efficient operation of that market, pending the revision of such rule, standard, procedure design feature, or software defect to preclude such manipulation of prices or impairment of efficiency.

2.4.3 Taking advantage of opportunities to sell at a higher price or buy at a lower price in a market other than an ISO Market shall not be deemed a form of withholding or otherwise inconsistent with competitive conduct.

2.4.4 The ISO shall monitor ISO Markets for other categories of conduct, whether by a single firm or by multiple firms acting in concert, that have material effects on prices in an ISO Market or other payments. The ISO shall: (i) seek to amend the foregoing list as may be appropriate to include any such conduct that would substantially distort or impair the competitiveness of any of the ISO Markets; and (ii) seek such other authorization to mitigate the effects of such conduct from the FERC as may be appropriate.

3 CRITERIA FOR IMPOSING MITIGATION MEASURES

3.1 Identification of Conduct Inconsistent with Competition

Conduct that may potentially warrant the imposition of a mitigation measure includes the categories described in Section 2.4 above. The thresholds listed in Section 3.1.1 below shall be used to identify substantial departures from competitive conduct indicative of an absence of workable competition.

3.1.1 Conduct Thresholds for Identifying Economic Withholding

The following thresholds shall be employed by the ISO to identify economic withholding that may warrant the mitigation of the bid from a resource and shall be determined with respect to a reference level determined as specified in Section 3.1.1.1:

For Energy Bids to be Dispatched as Imbalance Energy through the RTD Software: the lower of a 200 percent increase or \$100/MWh increase in the bid with respect to its Reference Level.

3.1.1.1 Reference Levels

(a) For purposes of establishing reference levels, bid segments shall be defined as follows:

1. the capacity of each generation resource shall be divided into 10 equal Energy bid segments between its minimum (P_{min}) and maximum (P_{max}) operating point.

A reference level for each bid segment shall be calculated each day for peak and off-peak periods on the basis of the following methods, listed in the following order of preference subject to the existence of sufficient data, where sufficient data means at least one data point per time period (peak or off-peak) for the bid segment. Peak periods shall be the periods Monday through Saturday from Hour Ending 0700 through Hour Ending 2200, excluding holidays. Off-Peak periods are all other hours.

1. Excluding non-positive proxy and mitigated bids, the accepted bid, or the lower of the mean or the median of a resource's accepted bids if such a resource has more than one accepted 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. Accepted and justified bids above the applicable soft cap, as set forth in Section 39.2 of this Tariff, will be included in the calculation of reference prices.

2. If the resource is a gas-fired unit that does not have significant energy limitations, the unit's default Energy Bid determined monthly as set forth in Section 5.11.5 (based on the incremental heat rate submitted to the ISO, adjusted for gas prices, and the variable O&M cost on file with the ISO, or the default O&M cost of \$6/MWh).

3. For non gas-fired units and gas-fired units that have significant energy limitations, 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 by the ISO, and provided the Market Participant has provided sufficient data on a unit's energy limitations and operating costs (opportunity cost for energy limited resources) in accordance with specifications provided by the ISO.
 4. The mean of the Economic Market Clearing Prices for the units' relevant location (Zone or node commensurate with the pricing granularity in effect) 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; or
 5. If sufficient data do not exist to calculate a reference level on the basis of the first, second, or fourth methods and the third method is not applicable or an attempt to determine a reference level in consultation with a Market Participant has not been successful, the ISO shall determine a reference level on the basis of:
 - i. the ISO's estimated costs of an Electric Facility, taking into account available operating costs data, opportunity cost, and appropriate input from the Market Participant, and the best information available to the ISO; or
 - ii. an appropriate average of competitive bids of one or more similar Electric Facilities.
- (b) The reference levels (\$/MWh bid price) for the different bid segments of each resource (or import bid curve of a Scheduling Coordinator at a Scheduling Point) shall be made monotonically non-decreasing by the ISO by proceeding from the lowest MW bid segment moving through each higher MW bid segment. The reference level of each succeeding bid segment shall be the higher of the reference level of the preceding bid segment or the reference level determined according to paragraph (a) above.

3.2 Material Price Effects

3.2.1 Market Impact Thresholds

In order to avoid unnecessary intervention in the ISO Market, Mitigation Measures for economic withholding shall not be imposed unless conduct identified as specified above causes or contributes to a material change in one or more of the ISO Market Clearing Prices (MCPs). Initially, the thresholds to be used by the ISO to determine a material price effect shall be as follows:

For Energy Bids to be Dispatched as Imbalance Energy through the RTD Software: the lower of an increase of 200 percent or \$50 per MWh in the projected Hourly Ex Post Price at any location (Zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff.

For Energy Bids to be Dispatched out of economic merit order to manage Intra-Zonal Congestion: if the price of the bid is \$50/MWh or 200 percent greater than the Dispatch Interval Ex Post Price at that location (Zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff.

Accepted and justified bids above the applicable soft cap, as set forth in Section 28.1.2 of this Tariff, will not be eligible to set the Market Clearing Price. Such bids shall be included in the Market Impact test, however, and, for purposes of this test only, shall be assumed to be eligible to set the Market Clearing Price.

3.2.2 Price Impact Analysis

3.2.2.1 Bids to be Dispatched as Imbalance Energy.

The ISO shall determine the effect on prices of questioned conduct through automated computer modeling and analytical methods. An Automatic Mitigation Procedure (AMP) shall identify bids that have exceeded the conduct thresholds and shall compute the change in projected Hourly Ex Post Prices as a result of simultaneously setting all such bids to their Reference Levels. If a change in the projected Hourly Ex Post Price exceeds the Impact threshold stated in Section 3.2.1, those bids would be kept mitigated at their default bid levels as specified in Section 4.2.2 below.

3.2.2.2 Bids to be Dispatched out of economic merit order to manage Intra-Zonal Congestion. If the price of the bid is \$50/MWh or 200 percent greater than the Dispatch Interval Ex Post Price at that location (Zone or node) commensurate with the relevant pricing structure in effect in accordance with the ISO Tariff, the bid price shall be mitigated to the reference price and the Scheduling Coordinator for that

resource shall be paid the greater of the reference price or the relevant Dispatch Interval Ex Post Price. Bids mitigated in accordance with this Section 3.2.2.2 shall not set the Dispatch Interval Ex Post Price.

3.2.3 Section 205 Filings

In addition, the ISO shall make a filing under Section 205 of the Federal Power Act with FERC seeking authorization to apply an appropriate mitigation measure to conduct that departs significantly from the conduct that would be expected under competitive market conditions but does not rise to the thresholds specified in Section 3.1.1 above, unless the ISO determines, from information provided by the Market Participant or Parties that would be subject to mitigation or other information available to the ISO that the conduct is attributable to legitimate competitive market forces or incentives. The following are examples of conduct that are deemed to depart significantly from the conduct that would be expected under competitive market conditions:

- (1) bids that vary with unit output in a way that is unrelated to the known performance characteristics of the unit, or
- (2) bids that vary over time in a manner that appears unrelated to the change in the unit's performance or to changes in the supply environment that would induce additional risk or other adverse shifts in the cost basis.

The conducts listed above are intended to be examples rather than a comprehensive list.

3.3 Consultation with a Market Participant

If a Market Participant anticipates submitting bids in an ISO Market administered by the ISO that will exceed the thresholds specified in Section 3.1 above for identifying conduct inconsistent with competition, the Market Participant may contact the ISO to provide an explanation of any legitimate basis for any such changes in the Market Participant's bids. If a Market Participant's explanation of the reasons for its bidding indicates to the satisfaction of the ISO, that the questioned conduct is consistent with competitive behavior, no further action will be taken. Upon request, the ISO shall also consult with a Market Participant with respect to the information and analysis used to determine reference levels under Section 3.1.1 above for that Market Participant.

4 MITIGATION MEASURES

4.1 Purpose

If conduct is detected that meets the criteria specified in Section 3, the appropriate mitigation measures described in this Section 4 shall be applied by the ISO. The conduct specified in Section 3.1.1 shall be remedied by the prospective application of a default bid measure as described in Section 4.2 for the specific hour that they violate the price and market impact thresholds.

4.2 Sanctions for Economic Withholding

4.2.1 Default Bid

A default bid shall be designed to cause a Market Participant to bid as if it faced workable competition during a period when: (i) the Market Participant does not face workable competition and (ii) has responded to such condition by engaging in the economic withholding of an Electric Facility. In designing and implementing default bids, the ISO shall seek to avoid causing an Electric Facility to bid below its marginal cost.

4.2.2 Implementation

- (a) If the criteria contained in Section 3 are met, the ISO may substitute a default bid for a bid submitted for an Electric Facility. The default bid shall establish a maximum value for each component of the submitted bid, equal to a reference level for that component determined as specified in Section 3.1.1 above.
- (b) The Mitigation Measures will be applied to 1) all incremental bids submitted to the real-time Imbalance Energy market during the pre-dispatch process prior to the real-time Imbalance Energy market based on the projected real-time MCPs that are computed during this process; and 2) to the Day-Ahead and the Hour-Ahead Energy markets when these markets are made operational.
- (c) An Electric Facility subject to a default bid shall be paid the MCP applicable to the output from the facility. Accordingly, a default bid shall not limit the price that a facility may receive unless the default bid determines the MCP applicable to that facility.
- (d) The ISO shall not use a default bid to determine revised MCPs for periods prior to the imposition of the default bid, except as may be specifically authorized by FERC.
- (e) The Mitigation Measures shall not be applied to Energy Bids projected to be Dispatched as Imbalance Energy through the RTD Software in the hours in which all Zonal Ex Post Prices are projected to be below \$91.87/MWh. If the Zonal Dispatch Interval Ex Post Price is projected to be above \$91.87/MWh in any ISO Zone, the Mitigation Measures shall be applied to all bids, except those from System Resources, in all ISO Zones. The ISO will apply Mitigation Measures to all bids taken out of merit order to address Intra-Zonal Congestion.
- (f) The Mitigation Measures shall not be applied to bids below \$25/MWh.
- (g) The posting of the MCP may be delayed if necessary for the completion of automated mitigation procedures.
- (h) Bids not mitigated under these Mitigation Measures shall remain subject to mitigation by other procedures specified in the ISO Tariff as may be appropriate.

4.3 Sanctions for Physical Withholding

The ISO may report a Market Participant the ISO determines to have engaged in physical withholding, including providing the ISO false information regarding the derating or outage of an Electric Facility, to the Federal Energy Regulatory Commission in accordance with Section 9.3.10.5 of the ISO Tariff. In addition, a Market Participant that fails to operate a Generating Unit in conformance with ISO Dispatch Instructions shall be subject to the penalties set forth in Section 11.2.4.1.2 of the ISO Tariff.

4.4 Duration of Mitigation Measures

Bids will be mitigated only in the specific hour that they violate the price and market impact thresholds.

5 FERC-ORDERED MEASURES

In addition to any mitigation measures specified above, the ISO shall administer, and apply when appropriate in accordance with their terms, such other mitigation measures as it may be directed to implement by order of the FERC.

6 DISPUTE RESOLUTION

If a Market Participant has reasonable grounds to believe that it has been adversely affected because a Mitigation Measure has been improperly applied or withheld, it may seek a determination in accordance with the dispute resolution provisions of the ISO Tariff. In no event, however, shall the ISO be liable to a Market Participant or any other person or entity for money damages or any other remedy or relief except and to the extent specified in the ISO Tariff.

7 EFFECTIVE DATE

These Mitigation Measures shall be effective as of the date they are approved by the FERC.

ISO TARIFF APPENDIX Q
Eligible Intermittent Resources Protocol

APPENDIX Q

Eligible Intermittent Resources Protocol

EIRP 1.3 Scope

EIRP 1.3.1 Scope of Application to Parties

This Protocol applies to the ISO and to:

- (a) Scheduling Coordinators (SCs);
- (b) Eligible Intermittent Resources; and
- (c) Participating Intermittent Resources.

EIRP 1.3.2 Liability of the ISO

Any liability of the ISO arising out of or in relation to this Protocol shall be subject to Section 14 of the ISO Tariff as if references to the ISO Tariff were references to this Protocol.

EIRP 2 PARTICIPATING INTERMITTENT RESOURCE CERTIFICATION

EIRP 2.1 No Mandatory Participation

Eligible Intermittent Resources may elect to be scheduled and settled as the ISO Tariff provides for Generating Units, and are not required to seek certification as Participating Intermittent Resources.

EIRP 2.2 Minimum Certification Requirements

Those Eligible Intermittent Resources that intend to become Participating Intermittent Resources must meet the following requirements.

EIRP 2.2.1 Agreements

The following agreements must be executed:

- (a) A Participating Generator Agreement that, among other things, binds the Participating Intermittent Resource to comply with the ISO Tariff;
- (b) A Meter Service Agreement for ISO Metered Entities; and
- (c) A letter of intent to become a Participating Intermittent Resource, which when executed and delivered to the ISO shall initiate the process of certifying the Participating Intermittent Resource. The form of the letter of intent shall be specified by the ISO and published on the ISO Home Page.

EIRP 2.2.2 Composition

The ISO shall develop criteria to determine whether one or more Eligible Intermittent Resources may be included within a Participating Intermittent Resource. Such criteria shall include:

- (a) A Participating Intermittent Resource must be at least 1 MW rated capacity.
- (b) A Participating Intermittent Resource may include one or more Eligible Intermittent Resources that have similar response to weather conditions or other variables relevant to forecasting Energy, as determined by the ISO.
- (c) Each Participating Intermittent Resource shall be electrically connected at a single point on the ISO Controlled Grid, except as otherwise permitted by the ISO on a case-by-case basis as may be allowed under the ISO Tariff.
- (d) The same Scheduling Coordinator must schedule all Eligible Intermittent Resources aggregated into a single Participating Intermittent Resource.

EIRP 2.2.3 Equipment Installation

A Participating Intermittent Resource must install and maintain the communication equipment required pursuant to EIRP 3, and the equipment supporting forecast data required pursuant to EIRP 6.

EIRP 2.2.4 Forecast Model Validation

The ISO must determine that sufficient historic and real-time telemetered data are available to support an accurate and unbiased forecast of Energy generation by the Participating Intermittent Resource, according to the forecasting process validation criteria described in EIRP 4.

EIRP 2.2.5 Information Requirements For Participating Intermittent Resource Export Fee

In order for the ISO to administer, implement and calculate the Participating Intermittent Resource Export Fee, each Participating Intermittent Resource jointly with, and through, its Scheduling Coordinator must provide the ISO with the following information and documents under the schedule and conditions set forth in this section. The ISO will maintain the confidentiality of all information and documents received under this section in accordance with ISO Tariff section 20 et seq.

- (a) A certification, in the form posted on the ISO Homepage, signed by an officer of the Participating Intermittent Resource and its Scheduling Coordinator, identifying (1) the Export Percentage under EIRP 5.3.2, if any, and basis thereof, and (2) each contract to sell Energy or capacity from the Participating Intermittent Resource, including for each such contract, the counterparty, start and end dates, delivery point(s), quantity in MW, other temporal terms, i.e., seasonal or hourly limitations.

The certification must be updated by resubmission to the ISO (1) upon a request to modify the composition of the Participating Intermittent Resource under EIRP 2.4.2; or (2) within ten (10) calendar days of final execution of a new contract or any change in counterparty, start and end dates, delivery point(s), quantity in MW, or other temporal terms, as described above, for any prior certified contract. All other contractual changes will not trigger the obligation for recertification;
- (b) Copies of all contracts, including changes, identified in the above-referenced certification; however, price information may be redacted from the contracts provided.

Each Participating Intermittent Resource, as of November 1, 2006, must initially provide the information requested by EIRP 2.2.5 in accordance with a market notice provided by the ISO to Participating Intermittent Resources. All other Eligible Intermittent Resources

must satisfy EIRP 2.2.5 in order to become a Participating Intermittent Resource after November 1, 2006.

EIRP 2.3 Notice of Certification

When all requirements described in EIRP 2.2 have been fulfilled, the ISO shall notify the Scheduling Coordinator and the representatives of the Eligible Intermittent Resources comprising the Participating Intermittent Resource that the Participating Intermittent Resource has been certified, and is eligible for the settlement terms provided under Section 11.2.4.5 of the ISO Tariff, as conditioned by the terms of this EIRP.

EIRP 2.4 Requirements After Certification

EIRP 2.4.1 Forecast Fee

Beginning on the date first certified, a Participating Intermittent Resource must pay the Forecast Fee for all metered Energy generated by the Participating Intermittent Resource over the duration of the commitment indicated in the letter of intent described in EIRP 2.2.1(c).

The amount of the Forecast Fee shall be determined so as to recover the projected annual costs related to developing Energy forecasting systems, generating forecasts, validating forecasts, and monitoring forecast performance, that are incurred by the ISO as a direct result of participation by Participating Intermittent Resources in ISO Markets, divided by the projected annual Energy production by all Participating Intermittent Resources.

The initial rate for the Forecast Fee, and all subsequent rate changes as may be necessary from time to time to recover costs incurred by the ISO for the forecasting conducted on the behalf of Participating Intermittent Resources, shall be posted on the

ISO Home Page. In no event shall the level of the Forecast Fee exceed the amount specified in ISO Tariff Appendix F, Schedule 4.

EIRP 2.4.2 Modification of Participating Intermittent Resource Composition

A Participating Intermittent Resource may seek to modify the composition of the Participating Intermittent Resource (e.g., by adding or eliminating an Eligible Intermittent Resource from the Participating Intermittent Resource). Such changes shall not be implemented without prior compliance with the written approval by the ISO. The ISO will apply consistent criteria and expeditiously review any proposed changes in the composition of a Participating Intermittent Resource.

EIRP 2.4.3 Changes in Scheduling Coordinator

This EIRP does not impose any additional requirement for ISO approval to change the Scheduling Coordinator for an approved Participating Intermittent Resource than would otherwise apply under the ISO Tariff to changes in the Scheduling Coordinator representing a Generating Unit.

EIRP 2.4.4 Continuing Obligation

A Participating Intermittent Resource must meet all obligations established for Participating Intermittent Resources under the ISO Tariff and this EIRP, and must fully cooperate in providing all data, other information, and authorizations the ISO reasonably requests to fulfill its obligation to validate forecast models, explain deviations, and implement the Participating Intermittent Resource Export Fees.

EIRP 2.4.5 Failure to Perform

If the ISO determines that a material deficiency has arisen in the Participating Intermittent Resource's fulfillment of its obligations under the ISO Tariff and this EIRP, and such Participating Intermittent Resource fails to promptly correct such deficiencies when notified by the ISO, then the eligibility of the Participating Intermittent Resource for the settlement accommodations provided in Section 11.2.4.5 of the ISO Tariff shall be suspended until such time that the unavailable data is provided or other material deficiency is corrected to the ISO's reasonable satisfaction. Such suspension shall not relieve the Scheduling Coordinator for the deficient Participating Intermittent Resource from paying the Forecast Fee over the duration of the period covered by the letter of intent described in EIRP 2.2.1(c).

EIRP 3 COMMUNICATIONS

EIRP 3.1 Forecast Data

The ISO may require various data relevant to forecasting Energy from the Participating Intermittent Resource to be telemetered to the ISO, including appropriate operational data, meteorological data or other data reasonably necessary to forecast Energy.

EIRP 3.2 Standards

The standards for communications shall be the monitoring and communications requirements for Generating Units providing only Energy and Supplemental Energy; as such standards may be amended from time to time, and published on the ISO Home Page.

EIRP 3.3 Cost Responsibility

An applicant for certification as a Participating Intermittent Resource is responsible for expenses associated with engineering, installation, operation and maintenance of required communication equipment.

EIRP 4 FORECASTING

The ISO is responsible for overseeing the development of tools or services to forecast Energy for Participating Intermittent Resources. The ISO will use its best efforts to develop accurate and unbiased forecasts, as limited by the availability of relevant explanatory data. Objective criteria and thresholds for unbiased, accurate forecasts shall be published on the ISO Home Page, and shall be used to certify Participating Intermittent Resources in accordance with EIRP 2.2.4.

EIRP 4.1 Hour-Ahead Forecast

The ISO shall develop expert, independent hourly forecasts of Energy generation on each Participating Intermittent Resource. A forecast shall be published each hour on the half hour for each of the next seven operating hours. Other forecasts, including a day-ahead forecast, may be developed at the ISO's discretion. The Scheduling Coordinator representing the Participating Intermittent Resource must use the Hour-Ahead Forecast that is available 30 minutes prior to the deadline for submitting the Preferred Hour-Ahead Schedule. The ISO shall use best efforts to provide reliable and timely forecasts. However, if the ISO fails to deliver the Hour-Ahead Forecast to the Scheduling Coordinator prior to 15 minutes before the deadline for submitting Preferred Hour-Ahead Schedules, then the Hour-Ahead Forecast shall be the most recent Energy forecast provided by the ISO to the Scheduling Coordinator for the operating hour for which Preferred Schedules are next due.

EIRP 4.2 Forecast Calibration

The ISO shall calibrate the forecast to eliminate bias as measured by net MWh deviations across any and all relevant time periods to minimize the expected cumulative net charges or payments that are recovered or allocated through Section 11.2.4.5 of the ISO Tariff.

EIRP 4.3 Confidentiality

The ISO shall maintain the confidentiality of proprietary data for each Participating Intermittent Resource in accordance with Section 20 of the ISO Tariff.

EIRP 5 SCHEDULING AND SETTLEMENT

EIRP 5.1 Schedules

Scheduling Coordinators shall be required to submit Preferred Hour-Ahead Energy Schedules (MWh) for the Generating Units that comprise each Participating Intermittent Resource that are identical, in the aggregate, to the Hour-Ahead Forecast published for that Participating Intermittent Resource (MWh).

EIRP 5.2 Settlement

After a Participating Intermittent Resource is certified, settlement shall be determined for each Settlement Period based on consistency of Schedules and bids submitted on behalf

of such Participating Intermittent Resources with the rules specified in the ISO Tariff and this Protocol.

No Supplemental Energy bids or Adjustment Bids may be submitted on behalf of a Participating Intermittent Resource. Submitting such bids shall render the Participating Intermittent Resource ineligible for settlement according to Section 11.2.4.5 of the ISO Tariff for that Settlement Period. Such activity will be monitored in accordance with EIRP 7.

EIRP 5.3 Participating Intermittent Resource Export Fee

EIRP 5.3.1 Exemptions

After November 1, 2006, Participating Intermittent Resources shall be subject to the Participating Intermittent Resource Export Fee, as set forth in Schedule 4 of Appendix F, for Energy generated, except to the extent the Participating Intermittent Resource is exempt under one or more of the following conditions:

- (a) The owner of a Participating Intermittent Resource, as of November 1, 2006, utilizes the Energy generated from the Participating Intermittent Resource to meet its own Native Load outside the ISO Control Area. Should any Participating Intermittent Resource subject to this exemption increase its Pmax set forth in the ISO's Master File by modification under EIRP 2.4.2, the exemption will not apply to the added capacity unless exempt under another subsection of EIRP 5.3.1.

If the Participating Intermittent Resource subject to this exemption changes ownership, the Participating Intermittent Resource Export Fee will apply, except where the prior exempt owner demonstrates that the entire output of the Participating Intermittent Resource continues to be delivered to the exempt owner under a power purchase agreement for the purpose of serving the prior exempt owner's Native Load. The exemption will then continue only for the period of the power purchase agreement as provided in accordance with EIRP 2.2.5 and cannot exceed the MW quantity originally exempted.

- (b) A Participating Intermittent Resource demonstrates in its certification under EIRP 2.2.5(a) an export contract with a starting term prior to November 1, 2006. An export contract is any power purchase agreement to sell Energy to any entity other than a load serving entity with an obligation under law or franchise to serve Demand within the ISO Control Area.

The exemption will apply to any extension of the current export contract through an evergreen or other existing extension provision. The exemption terminates upon termination of the export contract. Should any Participating Intermittent Resource subject to this exemption increase its Pmax set forth in the ISO's Master File by modification under EIRP 2.4.2, the exemption will apply only to Energy generated up to the contract quantity, unless the Participating Intermittent Resource demonstrates a basis for exemption under subsection (c) for the expanded capacity.

- (c) A Participating Intermittent Resource demonstrates in its certification under EIRP 2.2.5(a) a contract to sell Energy to a load serving entity with Native Load within the ISO Control Area. Energy Service Providers with contractual obligations with customers within the ISO Control Area would be deemed a load serving entity with an obligation to serve Native Load within the ISO Control Area.

The exemption will apply to any extension of the current contract through an evergreen or other existing extension provision. The exemption terminates upon termination of the contract. Should any Participating Intermittent Resource subject to this exemption increase its Pmax set forth in the ISO's Master File by modification under EIRP 2.4.2, the exemption will continue to apply only to Energy generated up to the contract quantity unless the Participating Intermittent Resource demonstrates a basis for exemption under this subsection (c) for the expanded capacity.

EIRP 5.3.2 Participating Intermittent Resource Export Percentage

Based on the information required in EIRP 2.2.5 and application of the exemptions to the Participating Intermittent Resource Export Fee in EIRP 5.3.2, the ISO will determine an "Export Percentage" for each Participating Intermittent Resource that will be calculated as the ratio of the Participating Intermittent Resource's Pmax in the ISO Master File minus the MW, subject to an exemption under EIRP 5.3.2 on a MW basis to the Participating Intermittent Resource's Pmax in the ISO Master File. For example, a Participating Intermittent Resource with a Pmax of 100 MW and a contract with an ISO Control Area load serving entity for 40 MW would have an export percentage of $(100-40)/100 = 60\%$. A Participating Intermittent Resource with Export Percentage greater than zero (0) will be deemed an Exporting Participant Intermittent Resource. The ISO will notify the Participating Intermittent Resource and its Scheduling Coordinator of the facility's Export Percentage. Any dispute regarding the ISO's determination of Export Percentage shall be subject to the dispute resolution procedures under Section 13 of the ISO Tariff.

EIRP 5.3.3 Quarterly Application of Participating Intermittent Resource Export Fee

Each quarter the ISO will charge Exporting Participating Intermittent Resources the Participating Intermittent Resource Export Fee, as set forth in Schedule 4 of Appendix F.

EIRP 5.3.4 Allocation of Credit for Participating Intermittent Resource Export Fees Received

Payments received by the ISO from application of the Participating Intermittent Export Fee in accordance with EIRP 5.3 shall be allocated as a credit on a quarterly basis to Scheduling Coordinators with Net Negative Uninstructed Deviations in proportion to the amount of Net Negative Uninstructed Deviations that each Scheduling Coordinator was assessed for Participating Intermittent Resources settlement charges for ISO Charge Type 721 during the prior quarter.

EIRP 5.3.5 Recording of Exemptions and Notice of Termination

The ISO will record any exemption period ending date, if applicable, for each Participating Intermittent Resource. At the conclusion of the exemption period, the ISO will notify the Scheduling Coordinator for the Participating Intermittent Resource that the facility is no longer exempt from the Participating Intermittent Resource Export Fee.

EIRP 5.3.6 Annual Confirmation

On December 31 of each calendar year, each Participating Intermittent Resource shall confirm in the form posted on the ISO Homepage, signed by an officer of the Participating Intermittent Resource, that the operations of the Participating Intermittent Resource are consistent with any certification(s) provided to the ISO under EIRP 2.2.5.

EIRP 5.3.7 Audit Rights

In addition to the rights set forth in ISO Tariff Section 4.6.9, the ISO shall have the right to contact any counterparty to a contract relied upon under EIRP 5.3.1 for purposes of determining compliance with this EIRP.

EIRP 6 DATA COLLECTION FACILITIES

The Participating Intermittent Resource must install and maintain equipment to collect, record and transmit data that the ISO reasonably determines is necessary to develop and support a forecast model that meets the requirements of EIRP 4.

EIRP 6.1 Wind Resources

A Participating Intermittent Resource powered by wind must install at least one meteorological tower at a project location that is representative of the microclimate within the project boundary.

The meteorological tower must rely on equipment typically used in the wind industry to continuously monitor weather conditions at a wind resource site. Data collected shall be consistent with requirements published on the ISO Home Page. Such data must be gathered and telemetered to the ISO in accordance with EIRP 3.

If objective standards developed by the ISO indicate that the meteorological data may not be sufficiently representative of conditions affecting Energy output or changes in Energy output by that Participating Intermittent Resource, then the ISO may require that additional meteorological equipment be temporarily installed at another location within the project boundary. The cost of such equipment, which may be temporarily installed by the Participating Intermittent Resource or the ISO, shall be the responsibility of the Participating Intermittent Resource.

If objective standards indicate that the data collected from such a temporary site contribute significantly to the development of an accurate and unbiased forecast, then the Participating Intermittent Resource shall be responsible for installing and arranging for the telemetry of data from an additional permanent meteorological tower at such site, and for the reasonable cost, if any, that the ISO may have incurred to install and remove the temporary equipment. Relocation of the original meteorological tower to the new site will be allowed if the ISO determines that a sufficiently accurate and unbiased forecast can be generated from a single relocated meteorological tower.

EIRP 6.2 Other Eligible Intermittent Resources

Eligible Intermittent Resources other than wind projects that wish to become Participating Intermittent Resources will be required to provide data of comparable relevance to estimating Energy generation. Standards will be developed as such projects are identified and will be posted on the ISO Home Page.

EIRP 7 PROGRAM MONITORING

The ISO shall monitor the operation of these rules, and will in particular seek to eliminate any gaming opportunities provided by the flexibility provided Participating Intermittent Resources to self-select participation on an hourly basis.

Participating Intermittent Resources are expected to schedule and otherwise perform in good faith, and not seek to act strategically in a manner that causes financial gain through systematic behavior, where such gain results solely from the settlement accommodations provided under ISO Tariff Section 11.2.4.5.

If requirements specified in this technical standard are not met, then Participating Intermittent Resource certification may be revoked pursuant to EIRP 2.4.5. Any patterns of strategic behavior by Participating Intermittent Resources will be tracked, and the statistical significance of such deviations will be used by the ISO to evaluate whether changes in the rules defined in this EIRP are appropriate.

The ISO will monitor the impact of rules for Participating Intermittent Resources on Imbalance Energy and Regulation costs to the ISO.

EIRP 8 AMENDMENTS

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 22.10 of the ISO Tariff.

ISO TARIFF APPENDIX R
UDP Aggregation Protocol (UDPAP)

ISO TARIFF APPENDIX R

UDP Aggregation Protocol (UDPAP)

UAP 1.3 Scope

There are two types of UDP Aggregation Classifications:

- (1) Basic UDP Aggregations: composed of Generating Units connected at the same substation and stepping up to the same voltage level bus bar, or
- (2) Custom UDP Aggregations: composed of Generating Units connected at different substations and/or different voltage levels, particularly where the Generating Units to be aggregated are separated by ISO Controlled Grid facilities. Examples of a proposed Custom UDP Aggregation include hydroelectric units operating on a common watershed (but having multiple different interconnection points), or geothermal units fed from a common geothermal steam supply.

UAP 2 SUBMITTAL OF A REQUEST FOR UDP AGGREGATION

Requests for UDP Aggregation are submitted to the ISO and must include the following documentation:

- (1) A completed UDP Aggregation Request form, which is available for downloading on the ISO website;
- (2) A simplified electrical one-line diagram, which illustrates each resource, the connection of the resources to each other and to the ISO Control Area Grid;
- (3) For Custom UDP Aggregations, a detailed description that explains physical operating interrelationships between the units, or, if there are no interrelationships, how the units are compatible and why an aggregation of these units for the purpose of calculating Uninstructed Deviation Penalties is reasonable.

UAP 3 ISO REVIEW OF A UDP AGGREGATION REQUEST

Upon receipt of a completed request form and accompanying attachments, the ISO shall review the request according to the criteria outlined herein. For Basic UDP Aggregations, the ISO shall review and approve or reject it within one week of receipt. The ISO shall review and approve or reject a request for a Custom UDP Aggregation within thirty (30) days of receipt.

UAP 3.1 Criteria for Reviewing a Request

UAP 3.1.1 Scheduling Coordinator and Interconnection Point

Uninstructed Deviations may be aggregated for resources that are:

- (1) Represented by the same Scheduling Coordinator and
- (2) Connected to the same ISO Controlled Grid bus and voltage level.

The ISO will consider, on a case-by-case basis, requests to aggregate Uninstructed Deviations among resources represented by the same Scheduling Coordinator but not sharing a common ISO Controlled Grid bus and voltage level based on an ISO review of impact on the ISO Controlled Grid. In particular, the ISO will consider whether the request concerns resources related by a common flow of fuel which cannot be interrupted without a substantial loss of efficiency of the combined output of all components; whether the Energy production from one resource necessarily causes Energy production from other resource(s); and whether the operational arrangement of resources determines the overall physical efficiency of the combined output of all of the resources.

UAP 3.1.2 Additional Criteria

Additional eligibility criteria for a UDP Aggregation are as follows:

- (1) Only Generating Units shall be eligible for UDP Aggregation. As a general rule, pump-generating Units (or a Physical Scheduling Plant [PSP] containing a pump-generating Unit) cannot be part of a UDP Aggregation. However, it is possible that generating Units could form a UDP Aggregation comprised entirely of pump-generating Units whose operation is uniform, that is, Units all operating in either Generation mode or all in pump mode, but never mixed.
- (2) UDP Aggregations cannot include any of the following:
 - (a) Load;
 - (b) Condition 2 Reliability Must Run (RMR) Units;
 - (c) Participating Intermittent Resources;
 - (d) Generating Units less than 5 MW; or
 - (e) Generating Units that span active or inactive Congestion Zones.
- (3) The resources must have ISO direct telemetry and must be fully compliant with the ISO's direct telemetry standards.
- (4) The Generating Units must have the same relative effect on all network elements for which the Generating Units have at least a five (5) percent effectiveness factor, that is, for those network elements for which a 1 MW change in the output of the Generating Unit changes the flow across that element by at least 0.05 MW. For the purposes of this item (4), the "same relative effect" means that the effectiveness factors of any Generating Unit relative to a network element cannot differ by more than 10% from the midpoint effectiveness factor of all the units. The midpoint effectiveness is the arithmetic mean of the two most different effectiveness factors to be aggregated.
- (5) Custom UDP Aggregations involving units not directly connecting to the ISO Controlled Grid must recognize the transfer limits and status of the intermediate local facilities.
- (6) The applicable Pmax of aggregated groups of resources will exclude units that are not operating.

UAP 3.1.3 Approval of a Request

If a UDP Aggregation request is approved, the ISO shall create a new unique Resource ID, which reflects the identity or location of the units and stipulates the UDP Aggregation, but which cannot be used for scheduling purposes. The ISO shall inform the Scheduling Coordinator of the approval and ask the Scheduling Coordinator to confirm the desired start date of the UDP Aggregation. When that confirmation has been received, the new aggregation will be entered into the ISO systems. Unless otherwise agreed to by the Scheduling Coordinator and the ISO, the UDP Aggregation will become effective on the first day of the month following approval. The Units in an approved UDP Aggregation are obligated to follow their individual schedules and instructions at all times.

UAP 3.1.4 Rejection of a Request

If the ISO determines that the proposed UDP Aggregation is likely to impact grid reliability or the reliability of transmission systems or equipment of intermediate entities between the relevant resources and the ISO grid, the request will be rejected. If the ISO rejects a request, the ISO shall inform the Scheduling Coordinator, and forward to it the reason for the rejection. The ISO may suggest alternative solutions if it has adequate time and data. The Scheduling Coordinator may choose to resubmit based on the ISO's recommendations, or to close the request.

UAP 4 MODIFICATIONS TO AN EXISTING UDP AGGREGATION

UAP.4.1 Status of UDP Aggregation

An approved UDP Aggregation shall be considered active until otherwise requested by the Scheduling Coordinator.

UAP 4.2 Suspension by the ISO

The ISO may temporarily suspend any aggregation as needed to ensure reliability. The ISO may also suspend previously approved UDP Aggregations if, due to changes to the grid, to the aggregated Generating Units, or to the facilities connecting aggregated Generating Units to the grid, the UDP Aggregation no longer meets the criteria set forth in Sections 3.1.1 and 3.1.2 of this ISO Protocol.

If the ISO must suspend the UDP Aggregation due to a forced outage or other unanticipated event, the ISO shall provide notice that the UDP Aggregation has been suspended as soon as practical after the affecting event, but in no case longer than 72 hours after that event. If the ISO must suspend the UDP Aggregation due to future changes, the ISO shall notify the affected Scheduling Coordinator (1) that the UDP Aggregation will be suspended and (2) when the UDP Aggregation will be suspended as soon as practical after the ISO determines the UDP Aggregation must be suspended.

The ISO shall write a report that explains the reason for the suspension and that specifies the effective date and time. The ISO will forward the report to the Scheduling Coordinator and take steps to have the aggregation removed from the ISO systems.

In the event that a resource in a UDP Aggregation changes from one Scheduling Coordinator to another, the UDP Aggregation will be suspended. In order to reinstate the aggregation, the new Scheduling Coordinator must submit a new request reflecting the change.

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

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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
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ISO TARIFF APPENDIX U
Standard Large Generator Interconnection Procedures (LGIP)

**Standard Large Generator
Interconnection Procedures (LGIP)**

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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.

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 results with 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 Applicable 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 commutator 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 Customer¹; 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

787 _____

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. 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 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

	Typical Calendar Days	Typical Cumulative Days
Load Flow		
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	7	21
At the ISO's direction, PTO develops contingency lists		
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
<p>*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.)</p>		
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

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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.

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 $\frac{1}{2}$ 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: $(\text{Current Tax Rate} \times (\text{Gross Income Amount} - \text{Present Value of Tax Depreciation})) / (1 - \text{Current Tax Rate})$. 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-pollled 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”)

Interconnection Procedures in Effect Prior to July 1, 2005 (“Amendment 39 Procedures”)

1 Applicability.

These Amendment 39 Procedures are applicable to Small Generating Facilities interconnecting to the ISO Controlled Grid and to Large Generating Facilities in accordance with Section 5.1 of the LGIP. The owner of a planned New Facility, or its designee, is referred to for purposes of this Appendix as a New Facility Operator.

2 Definitions.

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 Appendix.

2.2 Special Definitions for this Appendix.

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

Completed Application

Date For purposes of this Appendix, the date on which a New Facility Operator submits an Interconnection Application to the ISO that satisfies the requirements of the ISO Tariff and the TO Tariff of the Interconnecting PTO.

Completed Interconnection

Application An Interconnection Application that meets the information requirements as specified by the ISO and posted on the ISO Home Page.

Data Adequacy Requirement Any applicable minimum data requirements of the state agency responsible for generation siting or of any Local Regulatory Authority.

Delivery Upgrade The transmission facilities, other than Direct Assignment Facilities and Reliability Upgrades, necessary to relieve constraints on the ISO Controlled Grid and to ensure the delivery of energy from a New Facility to Load.

Designated Contact Person The person designated by each Participating TO to coordinate with the ISO on the processing and completion of all Interconnection Applications.

Direct Assignment Facility The transmission facilities necessary to physically and electrically interconnect a New Facility Operator to the ISO Controlled Grid at the point of interconnection.

Expedited Interconnection Agreement

A contract between a party which has submitted a Request for Expedited Interconnection Procedures and an Interconnection PTO under which the ISO and an Interconnecting PTO agree to process, on an expedited

basis, the Interconnection Application of a New Facility Operator and which sets forth the terms, conditions, and cost responsibilities for such interconnection.

Good Faith Deposit

The deposit paid to the ISO by a New Facility Operator with submission of its Interconnection Application in accordance with Section 3.2 of this Appendix, in an amount equal to \$10,000, including any interest that accrues on the original amount, less any bank fees or other charges assessed on the escrow account. A New Facility Operator may satisfy its deposit obligation through any commercially available financial instrument determined to be satisfactory by the ISO.

Interconnecting PTO

For purposes of this Appendix, the Participating TO that will supply the connection to the New Facility.

Interconnection Application

An application that requests interconnection of a New Facility to the ISO Controlled Grid and that meets the information requirements as specified by the ISO and posted on the ISO Home Page.

New Facility

A planned or Existing Generating Unit that requests, pursuant to this Appendix, to interconnect or modify its interconnection to the ISO Controlled Grid.

New Facility License

A license issued by a federal, state or Local Regulatory Authority that enables an entity to build and operate a Generating Unit.

New Facility Operator

The owner of a planned New Facility, or its designee.

Planning Procedures

Procedures governing the planning, expansion and reliable interconnection to the ISO Controlled Grid that the ISO may, from time to time, develop.

Reliability Upgrade

The transmission facilities, other than Direct Assignment Facilities, beyond the first point of interconnection necessary to interconnect a New Facility safely and reliably to the ISO Controlled Grid, which would not have been necessary but for the interconnection of a New Facility, including network upgrades necessary to remedy short circuit or stability problems resulting from the interconnection of a New Facility to the ISO Controlled Grid. Reliability Upgrades also include, consistent with WSCC practice, the facilities necessary to mitigate any adverse impact a New Facility's interconnection may have on a path's WSCC path rating.

Request for Expedited

Interconnection Procedures

A written request, submitted pursuant to Section 3.1.1 of this Appendix, by which a New Facility Operator can request expedited processing of its Interconnection Application.

System Impact Study

An engineering study conducted to determine whether a New Facility Operator's request for interconnection to the ISO Controlled Grid would require new transmission additions, upgrades or other mitigation measures.

3 Interconnection Application.

Unless the New Facility Operator has submitted a Completed Interconnection Application to the ISO prior to July 1, 2005, any New Facility Operators shall submit two copies of a Completed Interconnection Application to the ISO in the form specified by the ISO. The ISO will date stamp all copies of the Interconnection Application, retain one executed copy, and, within 1 Business Day, send the other copy to the Designated Contact Person of the Interconnecting PTO. Within 10 Business Days after the Interconnecting PTO receives an Interconnection Application, the ISO and the Interconnecting PTO shall determine whether the application is complete and the ISO will notify the New Facility Operator that its Interconnection Application is complete; or, in the event that the ISO, in consultation with the Interconnecting PTO, determines that the Interconnection Application is incomplete, the ISO will notify the New Facility Operator of the deficiencies or omissions in its application.

3.1 Expedited Procedures For New Facilities.

A New Facility Operator may submit a Request for Expedited Interconnection Procedures in accordance with Section 3.1.1 of this Appendix. The ISO will develop and post on the ISO Home Page the Planning Procedures applicable to such expedited processing of Interconnection Applications.

3.1.1 Request for Expedited Interconnection Procedures.

- (a) If it elects to expedite processing of its Completed Interconnection Application, a New Facility Operator shall submit a Request for Expedited Interconnection Procedures within 10 Business Days after receiving a copy of the System Impact Study for the proposed interconnection. The request should be submitted in writing to the ISO and the Interconnecting PTO.
- (b) Within 10 Business Days after receiving a Request for Expedited Interconnection Procedures, the ISO and Interconnecting PTO shall provide to applicant the results of any studies required in addition to the System Impact Study, and shall tender an Expedited Interconnection Agreement that requires the applicant to compensate the Interconnecting PTO for all costs reasonably incurred pursuant to the terms of the ISO Tariff and the Interconnecting PTO's applicable TO Tariff for processing the Completed Interconnection Application and providing the requested interconnection.
- (c) Concurrent with the provision, by the ISO and the Interconnecting PTO, of the studies referenced in subsection b, above, the Interconnecting PTO and the ISO shall provide to applicant their best estimate of the cost of any needed Direct Assignment Facilities and Reliability Upgrades, Delivery Upgrades, if requested by the New Facility Operator, and other costs that may be incurred in processing the Interconnection Application and providing the requested interconnection, however, unless otherwise agreed by the ISO, and the Interconnecting PTO, and the applicant, such cost estimate shall not be binding and the New Facility Operator shall compensate the ISO and the Interconnecting PTO for all actual interconnection costs reasonably incurred pursuant to the provisions of this Appendix and the Interconnecting PTO's TO Tariff.
- (d) The New Facility Operator shall execute and return to the Interconnecting PTO, with a copy to the ISO, such Expedited Interconnection Agreement within 10 Business Days of its receipt or the New Facility Operator's Interconnection Application will be deemed withdrawn. In that event, the New Facility Operator shall reimburse the ISO and the Interconnecting PTO for all costs reasonably incurred in the processing of the Interconnection Application, including the Request for Expedited Interconnection.

3.2 Good Faith Deposit.

- (a) Each New Facility Operator that submits an Interconnection Application will on the date of submission also provide a Good Faith Deposit to the ISO. The ISO shall hold the Good Faith Deposit in trust for each applicant in a separate, interest-bearing account.
- (b) The ISO shall refund the Good Faith Deposit, with accrued Interest, in the event that:
 - (i) The ISO determines that the New Facility is not responsible for any interconnection costs, other than study costs; or
 - (ii) The applicant withdraws its Interconnection Application or its Interconnection Application is deemed withdrawn.

3.3 Posting of Interconnection Applications and Non-disclosure.

The ISO will maintain on its OASIS site an updated list of all pending Interconnection Applications. As soon as practicable after the ISO receives a Completed Interconnection Application, the ISO will post the nearest substation, the capacity (MW) of the New Facility and the year the New Facility is proposed to begin operations. At the time it submits its Interconnection Application, a New Facility Operator may request in writing that the ISO and Interconnecting PTO not publicly disclose the identity of such New Facility Operator. Upon such request, the ISO and Interconnecting PTO will not disclose the identity of the applicant while its Interconnection Application is pending, unless disclosure is permitted under Section 20.3.1 of the ISO Tariff or in the event that an applicant's identity becomes otherwise publicly known.

4 Interconnection.

4.1 Detailed Planning Procedures.

The provisions set forth in this Appendix shall govern the interconnection of New Facilities to the ISO Controlled Grid, including the costs of such interconnection. The ISO shall also maintain on the ISO Home Page detailed Planning Procedures and interconnection standards for all such interconnections.

4.2 Studies.

- (a) Except as provided in Section 4.2(d) of this Appendix, for each Completed Interconnection Application, the ISO will direct the Interconnecting PTO to perform the required System Impact Study and Facility Study, and any additional studies the ISO determines to be reasonably necessary.
- (b) The Interconnecting PTO will complete or cause to be completed all studies directed by the ISO within the timelines provided in this section. Any studies performed by the ISO or by a third party at the direction of the ISO shall also be completed within the timelines provided in this section.
- (c) Each New Facility Operator shall pay the reasonable costs of all System Impact and Facility Studies performed by or at the direction of the ISO or the Interconnecting PTO, and any additional studies the ISO determines to be reasonably necessary in response to the Interconnection Application, including any iterative study costs required for other New Facility Operator's that have established a new queue position due to the New Facility Operator either withdrawing its Interconnection Application or because its queue position has been modified pursuant to the procedures in Section 4.4 of this Appendix. A New Facility Operator shall also pay the reasonable cost of Interconnecting PTO review of any System Impact Study or Facility Study that is performed by a New Facility Operator or its designee pursuant to subsection (d).

- (d) A New Facility Operator may perform its own System Impact Study and Facility Study, or contract with a third party to perform the System Impact Study and Facility Study, and shall so notify the ISO and the Interconnecting PTO of this election at the time it submits its Interconnection Application. Any such study or studies performed by a New Facility Operator or third party must be completed within the timelines identified in Sections 4.2.1 and 4.2.2 of this Appendix. To the extent that the ISO and Interconnecting PTO disagree on the adequacy of the New Facility Operator or third party-sponsored study, the ISO will determine the adequacy of the study, subject to the ISO's ADR Procedures. The ISO and Interconnecting PTO shall complete their review of the New Facility Operator's study within 30 calendar days of receipt of the completed study. The results of any study or studies performed by a New Facility Operator or third party must be approved by both the ISO and the Interconnecting PTO.

4.2.1 System Impact Study Procedures.

Within 10 Business Days after receiving a Completed Interconnection Application by the Interconnecting PTO, the ISO and the Interconnecting PTO will determine, on a non-discriminatory basis, whether a System Impact Study is required. The ISO and the Interconnecting PTO will make such determination based on the ISO Grid Planning Criteria and the transmission assessment practices outlined in the ISO Planning Procedures posted on the ISO Home Page. The ISO and Interconnecting PTO will utilize, to the extent possible, existing transmission studies. The System Impact Study will identify whether any Direct Assignment Facilities and Reliability Upgrades are needed, as well as, if requested by the New Facility Operator, any Delivery Upgrades necessary to deliver a New Facility's full output over the ISO Controlled Grid. The System Impact Study will also identify any adverse impact on Encumbrances existing as of the Completed Application Date.

If the ISO and the Interconnecting PTO determine that a System Impact Study is necessary, the Interconnecting PTO shall within 20 Business Days of receipt of Completed Interconnection Application, tender a System Impact Study Agreement that defines the scope, content, assumptions and terms of reference for such study, the estimated time required to complete it, and pursuant to which the applicant shall agree to reimburse the Interconnecting PTO for the reasonable actual costs of performing the required study. The New Facility Operator shall execute the System Impact Study Agreement and return it to the Interconnecting PTO within 10 Business Days, together with payment for the reasonable estimated cost, as provided by the Interconnecting PTO, of the System Impact Study. Alternatively, a New Facility Operator can request that the Interconnecting PTO proceed with the System Impact Study and abide by the terms, conditions, and cost assignment of the System Impact Study Agreement as determined through the ISO ADR Procedures, provided that such request is accompanied by payment for the reasonable estimated cost, as provided by the Interconnecting PTO, of the System Impact Study. If a New Facility Operator elects neither to execute the System Impact Study Agreement nor to rely upon the ISO ADR Procedures, such New Facility Operator's Completed Application will be deemed withdrawn. If the New Facility Operator's application is deemed withdrawn, the New Facility Operator will compensate the Interconnecting PTO for all reasonable costs incurred to that date in processing the Completed Interconnection Application.

The Interconnecting PTO will use due diligence to complete the System Impact Study within 60 calendar days of receipt of payment and the System Impact Study Agreement or initiation of the ISO ADR Procedures. If the Interconnecting PTO cannot complete the System Impact Study within 60 calendar days, the Interconnecting PTO will notify the New Facility Operator, in writing, of the reason why additional time is required to complete the required study and the estimated completion date.

4.2.2 Facility Study Procedures.

If a System Impact Study indicates that additions or upgrades to the ISO Controlled Grid are needed to satisfy a New Facility Operator's request for interconnection, the Interconnecting PTO shall, within 15 Business Days of the completion of the System Impact Study, tender to a New Facility Operator a Facility Study Agreement that defines the scope, content, assumptions and terms of reference for such study, the estimated time to complete the required study, and pursuant to which the applicant agrees to reimburse the Interconnecting PTO for the actual costs of performing the required Facility Study. The New Facility Operator shall execute the Facility Study Agreement and return it to the Interconnecting PTO within 10 Business Days, together with payment for the reasonable estimated cost, as provided by the Interconnecting PTO, of the Facility Study. Alternatively, a New Facility Operator may request that the Interconnecting PTO proceed with the Facility Study and abide by the terms, conditions, and cost assignment of the Facility Study Agreement ultimately determined through the ISO ADR Procedures, provided that such request is accompanied by payment for the reasonable estimated cost, as provided by the Interconnecting PTO, of the Facility Study. If a New Facility Operator elects either to not execute the Facility Study Agreement or to rely upon the ISO ADR Procedures, such New Facility Operator's Completed Application will be deemed withdrawn. If the New Facility Operator's application is deemed withdrawn, the New Facility Operator will compensate the Interconnecting PTO for all reasonable costs incurred to that date in processing the Completed Application.

The Interconnecting PTO will use due diligence to complete the Facility Study within 60 calendar days of receipt of payment and the Facility Study Agreement or initiation of the ISO ADR Procedures. If the Interconnecting PTO cannot complete the Facility Study within 60 calendar days, the Interconnecting PTO will notify the New Facility Operator, in writing, of the reason why additional time is required to complete the required study and the estimated completion date.

A New Facility Operator shall be entitled to amend its Completed Interconnection Application once without losing its queue position. Such amendment shall occur on or before 10 Business Days following the Date the Interconnecting PTO tenders a Facility Study Agreement. Specifically, as an alternative to executing and returning a Facility Study Agreement, a New Facility Operator may submit an amendment to its Completed Interconnection Application to reflect a revised configuration for its New Facility. The amended Completed Interconnection Application shall be treated in accordance with Section 4.2.1 of this Appendix and the New Facility Operator's Completed Interconnection Application shall not be deemed withdrawn, and it shall maintain its exiting queue position, if (a) the amended Completed Interconnection Application is received by the Interconnecting PTO within 10 Business Days of the Interconnecting PTO's tender of a Facility Study Agreement; and (b) the New Facility Operator has not submitted a previous amendment to the Completed Interconnection Application. In the event a New Facility Operator amends its Completed Interconnection Application, it will be responsible for any additional study costs that result from that amendment, including costs associated with revisions to studies for other applicants holding later queue positions.

4.3 Execution of Interconnection Agreement.

Following completion of the Facilities Study, a New Facility Operator proposing to interconnect a Large Generating Facility shall continue the interconnection process in accordance with Section 11.2 of the LGIP. Within 10 Business Days of receipt of a completed Facility Study, a New Facility Operator proposing to interconnect a Small Generating Facility shall request the Interconnecting PTO to provide to such applicant an Interconnection Agreement. The Interconnecting PTO shall provide an Interconnection Agreement to an applicant within 30 Business Days of receipt of the request for an Interconnection Agreement. If the ISO and Interconnecting PTO determine, pursuant to Sections 4.2.1 and 4.2.2 of this Appendix, that either:

- (a) a New Facility Operator's Interconnection Application can be accommodated and that such New Facility Operator will not incur costs for Reliability Upgrades, the New Facility Operator shall

execute the Interconnection Agreement within 10 Business Days of receipt of the Interconnection Agreement; or

- (b) a New Facility Operator's Interconnection Application will necessitate Reliability Upgrades, the New Facility Operator shall execute the Interconnection Agreement within 30 Business Days of receipt of the Interconnection Agreement or, if a New Facility Operator and the Interconnecting PTO are unable to agree on the rates, terms and conditions of the Interconnection Agreement, the New Facility Operator may request that the Interconnecting PTO file an unexecuted Interconnection Agreement at FERC. If a New Facility Operator does request that the Interconnecting PTO file an unexecuted Interconnection Agreement at FERC, the New Facility Operator shall agree to abide by the rates, terms and conditions of such Interconnection Agreement ultimately determined by FERC to be just and reasonable.

4.4 Queuing.

- (a) The ISO and Interconnecting PTO will process all Interconnection Applications based on the New Facility's Completed Application Date.
- (b) The queue position for each New Facility that has submitted an Interconnection Application will be established according to the Completed Application Date and the New Facility's compliance with the milestones set forth in Section 4.4.1 of this Appendix.
- (c) For any New Facility Operator that submitted a request to interconnect to a Interconnecting PTO prior to June 1, 2002 (the effective date of the Amendment 39 Procedures), such New Facility Operator's position in the queue will be based on its Completed Application Date as that term was defined in the Interconnecting PTOs TO Tariff in effect at the time the New Facility Operator submitted a request to interconnect to the Interconnecting PTO.

4.4.1 Queuing Milestones.

- (a) To maintain its queue position, each New Facility Operator must timely comply with the requirements of the ISO Tariff and the TO Tariff of the Interconnecting PTO and must, within 6 months of its Completed Application Date, satisfy all applicable Data Adequacy Requirements of state and local siting and other regulatory authorities. Any New Facility Operator not subject to state siting requirements must satisfy the information requirements set forth in 18 C.F.R. § 2.20. The ISO will permit a New Facility Operator to retain its queue position if such New Facility Operator requests an extension of the six-month period at least 5 Business Days prior to the expiration of such period. Such extension will be limited to one period of 30 Business Days and additional extensions shall not be granted. A New Facility Operator that does not maintain its queue position, but later satisfies the Data Adequacy Requirements, or the requirements of 18 C.F.R. § 2.20 if applicable, will be placed in a queue position comparable to that of other New Facility Operators that have satisfied the Data Adequacy Requirements, or the requirements of 18 C.F.R. § 2.20, as of the same date. At that time, the ISO and the Interconnecting PTO will determine whether a new System Impact Study must be performed based on the revised queue position of such New Facility Operator.
- (b) Upon satisfaction of the Data Adequacy Requirements, or the requirements of 18 C.F.R. § 2.20 if applicable, each New Facility Operator, in order to maintain its queue position, must obtain a New Facility License within 15 months after satisfying the Data Adequacy Requirements. A New Facility Operator that does not obtain a New Facility License within the allowed time and does not maintain its queue position, but later obtains a New Facility License, will be placed in a queue position comparable to other New Facility Operators that have satisfied comparable milestones as of that date.

- (c) Any New Facility whose New Facility License or building permit expires or is rescinded will not maintain its queue position.
- (d) A New Facility Operator that has submitted a dispute under Article 13 of the ISO Tariff regarding any part of this Appendix may request that the presiding judge, arbitrator, or mediator of the dispute suspend its obligation to meet milestones in order to maintain its queue position. In the event such a suspension is granted, the New Facility Operator must satisfy the missed milestones specified in this Section 4.4.1 of this Appendix within 30 calendar days of the date the decision on the dispute becomes final.

4.5 Coordination of Critical Protective Systems.

New Facility Operators shall coordinate with the ISO, Participating TOs and UDCs to ensure that a New Facility Operator's Critical Protective Systems, including relay systems, are installed and maintained in order to function on a coordinated and complementary basis with ISO Controlled Grid Critical Protective Systems and the protective systems of the Participating TOs and UDCs. The ISO and Participating TOs will make available all information necessary for a New Facility Operator to determine whether its Critical Protective Systems are compatible with those of the ISO, Participating TOs and UDCs. The ISO and New Facility Operators shall also coordinate with entities that own, operate or control facilities outside of the ISO Controlled Grid to ensure that a New Facility's Critical Protective Systems function on a coordinated and complementary basis with such entities Critical Protective Systems.

5 Cost Responsibility of New Facility Operators.

- (a) Each New Facility Operator shall pay the costs of required studies in accordance with Section 4.2 of this Appendix and the costs identified in this Section 5. The ISO and Interconnecting PTO will provide each New Facility Operator an estimate of its total cost responsibility under this Section. A New Facility Operator shall be responsible for the actual costs of all Direct Assignment Facilities and Reliability Upgrades necessitated by its Completed Interconnection Application. The Interconnecting PTO will provide each New Facility Operator a detailed record of the actual costs assessed to it under this Section. A New Facility Operator may request the Interconnecting PTO to provide any additional information reasonably necessary to audit the actual costs the New Facility Operator is assessed.
- (b) The ISO and Interconnecting PTO will process all Interconnection Applications, and determine the cost responsibility of each New Facility Operator based on the New Facility Operator's Completed Application Date or, if applicable, based on the queue position determined by the procedure described in Section 4.4.1(b) of this Appendix. The ISO and Interconnecting PTO will process simultaneously all interconnection requests with the same Completed Application Date.
- (c) Each New Facility Operator shall pay the costs of planning, installing, operating and maintaining the following facilities: (i) Direct Assignment Facilities, and, if applicable, (ii) Reliability Upgrades. In addition, each New Facility Operator shall implement all existing operating procedures necessary to safely and reliably connect the New Facility to the facilities of the Interconnecting PTO and to ensure the ISO Controlled Grid's conformance with the ISO Grid Planning Criteria, and shall bear all costs of implementing such operating procedures. The New Facility Operator shall be responsible for the costs of Reliability Upgrades only if the necessary facilities are not included in the ISO Controlled Grid Transmission Expansion Plan approved as of the New Facility Operator's Completed Application Date, or the date for the installation of a facility is advanced by the interconnection of the New Facility, in which case the New Facility Operator shall be responsible only for the incremental costs associated with the earlier installation of the facility.
- (d) Each New Facility Operator may, at its own discretion, sponsor, pursuant to Section 3.2 of the ISO Tariff, any Delivery Upgrades.

5.1 Maintenance of Encumbrances.

No New Facility shall adversely affect the ability of the Interconnecting PTO to honor its Encumbrances existing as of the time a New Facility submits its Interconnection Application to the ISO. The Interconnecting PTO, in consultation with the ISO, shall identify any such adverse effect on its Encumbrances in the System Impact Study performed under Section 4.2.1 of this Appendix. To the extent the Interconnecting PTO determines that the connection of the New Facility will have an adverse effect on Encumbrances, the New Facility Operator shall mitigate such adverse effect.

5.2 Settlement of Interconnection Costs.

Payment for Direct Assignment Facilities and Reliability Upgrades shall be made by the New Facility Operator to the Interconnecting PTO pursuant to the terms of payment set forth in the Interconnection Agreement between the parties.

6 Energization.

Neither the ISO nor the Interconnecting PTO shall be obligated to energize, nor shall the New Facility Operator be entitled to have its interconnection to the ISO Controlled Grid energized, unless and until an Interconnection Agreement has been executed, or filed at FERC pursuant to Section 4.3 of this Appendix, and becomes effective and such New Facility Operator has demonstrated to the ISO's reasonable satisfaction that it has complied with all of the requirements of this Appendix.

ISO TARIFF APPENDIX X
Dynamic Scheduling Protocol (DSP)

ISO TARIFF APPENDIX X

Dynamic Scheduling Protocol (DSP)

DSP 2 CONSISTENCY WITH NERC/WECC POLICIES AND REQUIREMENTS

DSP 2.1 Scheduling and operation of dynamic scheduling functionalities must comply with all applicable NERC and WECC policies and requirements regarding inter-Control Area scheduling, in accordance with Section 4.5.4.3 of the ISO Tariff.

DSP 2.2 Scheduling and operation of dynamic scheduling functionalities must be consistent with the NERC Dynamic Transfer White Paper and all NERC standards or policies.

DSP 2.3 All new dynamic functionality implementations may be subject to NERC-specified peer review.

DSP 3 CONTRACTUAL RELATIONSHIPS

DSP 3.1 The Host Control Area and all Intermediary Control Areas must each execute an Interconnected Control Area Operating Agreement ("ICAOA") with the ISO, with accompanying service schedule, or a special agreement particular to the operation of the functionality supporting dynamic imports of Energy, Supplemental Energy, and/or Energy associated with non-regulating Ancillary Services to the ISO Control Area.

DSP 3.2 The Scheduling Coordinator for the System Resource must execute a special agreement with the ISO governing the operation of the dynamic scheduling functionality, which agreement will include a provision for its termination based on failure to comply with these standards.

DSP 3.3 The Scheduling Coordinator for the System Resource must have the necessary operational and contractual arrangements in place with the Host Control Area (see Section 5 below). Such arrangements must include the Host Control Area operator's ability to receive telemetry from the System Resource and to issue a dynamic schedule signal pertinent to that System Resource to the ISO. Proof of such arrangements must be provided to the ISO.

DSP 4 COMMUNICATIONS, TELEMETRY, AND OTHER TECHNICAL REQUIREMENTS

DSP 4.1 The communication and telemetry requirements set forth in the ISO's Standards for Imports of Regulation will apply to all dynamic schedules, except for (a) those dynamic functionalities established prior to the ISO Operations Date, (b) the requirements that are specific solely to Regulation, and (c) the requirements set forth below.

DSP 4.2 Dedicated dual redundant communications links between the ISO's EMS and the Host Control Area EMS are required.

DSP 4.3 The primary circuit will be T1-class, or equivalent, utilizing the inter-control center communications protocol ("ICCP"). The backup circuit will be diversely routed between the Host Control Area EMS and the ISO Control Area EMS on separate physical paths and devices.

DSP 4.4 Dedicated dual redundant communications links between the Host Control Area EMS and every Intermediary Control Area EMS are required.

DSP 4.5 The Control Area hosting a dynamically scheduled System Resource must have a mechanism implemented to override the associated dynamic signal.

DSP 4.6 The dynamic signal must be properly incorporated into all involved Control Areas' ACE equations.

DSP 4.7 The System Resource must have communications links with the Host Control Area consistent with these standards.

DSP 5 LIMITS ON DYNAMIC IMPORTS

DSP 5.1 The ISO reserves the right to establish limits applicable to the amount of any Ancillary Services and/or Supplemental Energy imported into the ISO Control Area, whether delivered dynamically or statically. Such limits may be established based on any one, or a combination, of the following considerations: a percentage of, or a specific import limit applicable to, total ISO Control Area requirements; a percentage at, or a specific import limit applicable to, a particular Scheduling Point or a branch group; a percentage of, or a specific import limit applicable to, total requirements in a specific Congestion Zone; or operating factors which may include, but are not limited to, operating nomograms, Remedial Action Schemes, protection schemes, scheduling and curtailment procedures, or any potential single points of failure associated with the actual delivery process.

DSP 5.2 The ISO may, at its discretion, either limit or forego procuring Ancillary Services at particular Control Area interties to ensure that Operating Reserves are adequately dispersed throughout the ISO Control Area as required by WECC Minimum Operating Reliability Criteria ("MORC").

DSP 5.3 A dynamically scheduled System Resource and its schedules must be permanently associated with a particular ISO intertie (the ISO may, from time to time and at its discretion, allow for a change in such pre-established association of the dynamically scheduled System Resource with a particular ISO intertie).

DSP 6 OPERATING AND SCHEDULING REQUIREMENTS

DSP 6.1 For any operating hour for which Energy, Supplemental Energy, and/or Ancillary Services (and associated Energy) is scheduled dynamically to the ISO from the System Resource, a firm (or non-interruptible for that hour) matching transmission service must be reserved across the entire dynamic schedule transmission path external to the ISO Control Area.

DSP 6.2 All dynamic schedules associated with newly implemented dynamically scheduled System Resources must be electronically tagged (e-tagged).

DSP 6.3 Formal inter-Control Area dynamic schedules may be issued only by the dynamically scheduled System Resource's Host Control Area and must be routed through the EMSs of all Intermediary Control Areas (such schedules would be considered "wheel-through" schedules by Intermediary Control Areas).

DSP 6.4 The ISO will treat dynamically scheduled Energy as a resource contingent firm import. The ISO will procure (or allow for self-provision of) WECC MORC-required Operating Reserves for loads served by dynamically scheduled System Resources.

- DSP 6.5** All Energy schedules associated with dynamically scheduled imports of Spinning Reserve and Non-Spinning Reserve will be afforded similar treatment (i.e., resource contingent firm).
- DSP 6.6** The dynamic signal must be integrated over time by the Host Control Area for every operating hour.
- DSP 6.7** Notwithstanding any dispatches of the System Resource in accordance with the ISO Tariff, the ISO shall have the right to issue operating orders to the System Resource either directly or through the Host Control Area for emergency or contingency reasons, or to ensure the ISO's compliance with operating requirements based on WECC or NERC requirements and policies (e.g., WECC's Unscheduled Flow Reduction Procedure). However, such operating orders may be issued only within the range of the ISO-accepted Energy, Ancillary Services, and/or or Supplemental Energy Schedules and bids for a given operating hour (or the applicable "sub-hour" interval).
- DSP 6.8** If there is no dynamic schedule in the ISO's Day-Ahead, Hour-Ahead, or Supplemental Energy markets, the dynamic signal must be at "zero" ("0") except when in response to ISO's Dispatch Instructions associated with accepted Ancillary Services and/or Supplemental Energy bids.
- DSP 6.9** The Scheduling Coordinator of the dynamically scheduled System Resource must have the ability to override the associated dynamic schedule in order to respond to the operating orders of the ISO or the Host Control Area.
- DSP 6.10** Unless the dynamically scheduled System Resource (1) is implemented as a directly-telemetered load-following functionality, (2) is base-loaded Regulatory Must Take Generation, or (3) responds to an ISO intra-hour Dispatch Instruction, the dynamic schedule representing such resource must follow WECC-approved practice of 20-minute ramps centered at the top of the hour. The ISO does not provide any special settlements treatment nor offer any ISO Tariff exemptions for dynamic load following functionalities.
- DSP 6.11** In real time the dynamic schedule may not exceed the maximum value established by the sum of the Day-Ahead and Hour-Ahead accepted Energy and Ancillary Services Schedules plus any accepted Supplemental Energy bids plus any response to the ISO's real-time Dispatch Instructions. The composite value of the dynamic schedule derived from the Day-Ahead and Hour-Ahead accepted Schedules plus any Supplemental Energy bids and Dispatch Instruction response represents not only the estimated dynamically scheduled System Resource's Energy but also the transmission reservation on the associated ISO intertie.
- DSP 6.12** Only one dynamically scheduled System Resource may be associated with any one physical generating resource.
- DSP 6.13** If the Scheduling Coordinator for the dynamically scheduled System Resource desires to participate in ISO's Regulation market, all provisions of the ISO's Standards for Imports of Regulation shall apply.

DSP 7 CERTIFICATION, TESTING, AND PERFORMANCE MONITORING OF DYNAMIC IMPORTS OF ANCILLARY SERVICES

Scheduling Coordinators and Host Control Areas that are already certified under the ISO's Standards for Imports of Regulation will be deemed to have fulfilled the technical implementation requirements of this Protocol; however, such Scheduling Coordinators

and Control Areas must still be certified separately for each non-Regulating Ancillary Service (all presently implemented)

Regulation import functionalities may be subject to review to ensure consistency between such functionalities and the requirements of this Protocol). Scheduling Coordinators and Host Control Areas that wish to be certified for imports of Regulation shall be subject to certification under the Standards for Imports of Regulation, subject to verification of consistency with the requirements of this Protocol.

- DSP 7.1** The Scheduling Coordinator and Host Control Area operator must jointly request the certification of a System Resource to provide Ancillary Services for the ISO Control Area and cooperate in the testing of such System Resource (see the "Scheduling Coordinator & Host Control Area Operator Request for Certification of Dynamic Imports of Ancillary Services" certification form attached as Attachment A to this Protocol).
- DSP 7.2** Only ISO tested and certified System Resources will be allowed to bid and/or self-provide Ancillary Services into the ISO Control Area.
- DSP 7.3** Dynamic Ancillary Services imports will be certified through testing, in accordance with the relevant sections of the ISO's Operating Procedure G-213. All requests for certification of dynamic Ancillary Services imports will be reviewed and approved by the ISO with respect to any technical limitations imposed by existing operational considerations, such as Remedial Action Schemes, operating nomograms, and scheduling procedures. These reviews may impose certain Ancillary Services import limits in addition to those outlined in Section 4.1. Therefore, interested parties are advised and encouraged to contact the ISO before they begin the process of the necessary systems design, preparation, and implementation for import of Ancillary Services to the ISO Control Area.
- DSP 7.4** The ISO will measure the performance of the dynamic Energy schedule associated with accepted Ancillary Services bids against (1) the awarded range of Ancillary Service capacity; (2) the certified limits; and (3) the bid ramp rate, which shall be validated by the ISO against the certified ramp rate.
- DSP 7.5** The Scheduling Coordinator for the System Resource and the Host Control Area must notify the ISO should any changes, modifications, or upgrades affecting control and/or performance of the System Resource be made. Upon such notification, the ISO, at its discretion, may require that the System Resource and Host Control Area be re-certified to import Ancillary Services into the ISO Control Area.
- DSP 8** **COMPLIANCE, LOSSES, AND FINANCIAL SETTLEMENTS**
- DSP 8.1** Energy delivered in association with dynamically scheduled System Resources will be subject to all provisions of the ISO's Imbalance Energy markets, including Uninstructed Deviation Penalties ("UDP") (just as is the case with ISO intra-Control Area Generating Units of Participating Generators).
- DSP 8.2** Dynamically scheduled and delivered Ancillary Services will be subject to the ISO's compliance monitoring and remedies, just as any ISO intra-Control Area Generating Units of Participating Generators.
- DSP 8.3** All Day-Ahead and Hour-Ahead submitted dynamic schedules shall be subject to ISO Congestion mitigation and as such may not exceed their transmission reservations in real time (with the exception of intra-hour Dispatch Instructions of the Energy associated with accepted Ancillary Services or Supplemental Energy bids).

- DSP 8.4** All dynamically scheduled and delivered Energy shall be subject to the standard ISO transmission loss calculation associated with the particular inertia (“TMMs” or ISO market redesign alternative).
- DSP 8.5** Any transmission losses attributed to the dynamic schedule on transmission system(s) external to the ISO Control Area will be the responsibility of the owner(s)/operator(s) of the dynamically scheduled System Resource.
- DSP 8.6** A predetermined, mutually agreed, and achievable “Pmax-like” fixed MW value will be established for every dynamically scheduled System Resource to be used as the basis for the UDP calculation. Responsible Scheduling Coordinators will be able to report de-rates affecting the dynamically scheduled System Resource via the ISO’s “SLIC” outage reporting system.
- DSP 8.7** Should there be any need or requirement, whether operational or procedural, for the ISO to make real time adjustments to the ISO’s inter-Control Area schedules (to include curtailments), dynamic schedules shall be treated in the same manner as similarly situated and/or effective static ISO schedules.

DSP ATTACHMENT A

Scheduling Coordinator & Host Control Area Operator

Request for Certification of

Imports of Spinning and Non-Spinning Reserves for which the associated Energy is delivered dynamically from a System Resource

In accordance with the ISO Tariff, Protocols and Operating Procedures, _____, as Scheduling Coordinator, and _____, as Host Control Area operator (as such term is referred to in the ISO Dynamic Scheduling Protocol), collectively referred to as "Parties," or individually as "Party," hereby request the certification of the Parties and the System Resource(s) identified in the table below as a provider of Ancillary Services and associated Energy to the ISO Control Area subject to the Dynamic Scheduling Protocol. Further, the Parties acknowledge that their ability to import Ancillary Services and associated Energy will be tested for certification in accordance with ISO Operating Procedure G-213.

With this request for certification, the Parties recognize that the ISO Tariff, Protocols, and applicable agreements require the Host Control Area operator to issue dynamic Energy schedules to the ISO based on the Scheduling Coordinator's self-provided or bid external imports of non-Regulation Ancillary Services from the System Resource(s) at any time during the operating hour.

With this request for certification, the Host Control Area operator represents and warrants that it has in place the required communications links with the ISO Control Area in order to facilitate the delivery of Ancillary Services and associated Energy from the System Resource.

With this request for certification, the Scheduling Coordinator represents and warrants that it has made the appropriate arrangements for and has put in place the equipment and services necessary for the delivery of Ancillary Services and associated Energy from the System Resource to the point of interchange ("Scheduling Point") with the ISO Control Area in accordance with the Dynamic Scheduling Protocol.

The Scheduling Coordinator further certifies that any and all dynamic imports of Energy associated with self-provided or bid imports of non-Regulation Ancillary Services will be deliverable over non-interruptible, non-recallable transmission rights, from the source of the associated Energy to the Scheduling Point with the ISO Control Area.

System Resource	External Host Control Area in which System Resource is Located	Scheduling Point (ISO interchange ID)	Maximum Amount of Ancillary Services Capacity to be Certified (MW)	Maximum Ramp Rate to be Certified (MW/minute)
1				
2				
3				
4				
5				

Subsequent to the initial filing of this request for certification with the ISO, any prospective changes jointly made by the Parties may be filed with the Scheduling Coordinator's ISO Client Relations representative, who will acknowledge the receipt of such requested changes and indicate the date on which such changes may be tested and become effective if ISO testing proves successful. Such changes will be made by the ISO as soon as practicable, with reasonable efforts made to implement them within sixty (60) days of receipt of the requested changes.

This document _____ (does) _____ (does not) contain requested changes to previously effective certification.

Certification Requested By:

_____, as the Scheduling Coordinator

Name: _____

Title: _____

Date: _____

_____, as the Host Control Area Operator

Name: _____

Title: _____

Date: _____

CERTIFICATION REQUEST ACKNOWLEDGED by:

California Independent System Operator Corporation

Name: _____

Title: _____

Date: _____

ISO TARIFF APPENDIX Y
Scheduling Protocol (SP)

Scheduling Protocol (SP)

SP 3.2 Day-Ahead Market

The Day-Ahead Market is a forward market for Energy and Ancillary Services. The Day-Ahead Market operates individually for each Settlement Period of the Trading Day. The Day-Ahead Market starts at 6:00 pm two days ahead of the Trading Day and ends at 1:00 pm on the day ahead of the Trading Day, at which time the ISO issues the Final Day-Ahead Schedules.

SP 3.2.1 By 6:00 pm, Two Days Ahead

By 6:00 pm two days ahead of the Trading Day (for example, by 6:00 pm on Monday for the Wednesday Trading Day), the ISO will publish, via WEnet, the following information for each Settlement Period of the Trading Day:

- (a) a forecast of conditions on the ISO Controlled Grid, including transmission line and other transmission facility Outages;
- (b) a forecast of Generation Meter Multipliers (GMMs), as developed in accordance with Section 27.2.1, at each Generator location and Scheduling Point;
- (c) a forecast of system Demands by Zone;
- (d) an estimate of the Ancillary Services requirements for the ISO Control Area (see the ASRP for the details on these requirements);
- (e) a forecast of Loop Flows over interfaces with other Control Areas;
- (f) a forecast of the potential for Congestion conditions;
- (g) a forecast of total and Available Transfer Capacity over certain rated transmission paths and Inter-Zonal Interfaces;
- (h) a description of any temporary adjustments to Ancillary Service standards that the ISO has determined by that time to make, in accordance with Section 8.2.2.

SP 3.2.1.1 By 5:00 am, One Day Ahead

By no later than 5:00 am on the day before the Trading Day, the ISO will notify Scheduling Coordinators of the Energy Requirements from any Reliability Must-Run Units which the ISO requires to run in the Trading Day, except in those instances where a Reliability Must-Run Unit requires more than one day's notice, in which case the ISO may notify the applicable Scheduling Coordinator more than one day in advance of the Trading Day;

SP 3.2.1.2 By 6:00 am, One Day Ahead

By no later than 6:00 am on the day before the Trading Day, Scheduling Coordinators that have been notified that a Reliability Must-Run Unit is required to run in the Trading Day will inform the ISO, with regard to each hour for which the ISO has provided such

notice, whether the RMR Owner will take payment from the market or under the RMR Contract.

SP 3.2.2 [Not Used]

SP 3.2.3 By 6:30 am, One Day Ahead

By 6:30 am on the day ahead of the Trading Day (for example, by 6:30 am on Tuesday for the Wednesday Trading Day) and for each Settlement Period of the Trading Day: the ISO will provide to UDCs, via WEnet, the sum of the Scheduling Coordinators' Direct Access Demand Forecasts by UDC Service Area; and

SP 3.2.4 By 8:00 am, One Day Ahead

By 8:00 am on the day ahead of the Trading Day (for example, by 8:00 am on Tuesday for the Wednesday Trading Day), and for each Settlement Period of that Trading Day, Firm Transmission Rights owners will notify the ISO, via the Secondary Registration System or other means established by the ISO, of any transaction of Firm Transmission Rights and of any changes in Scheduling Coordinators' rights to schedule the use of Firm Transmission Rights at particular Inter-Zonal Interfaces.

SP 3.2.5 By 8:30 am, One Day Ahead

By 8:30 am on the day ahead of the Trading Day (for example, by 8:30 am on Tuesday for the Wednesday Trading Day), and for each Settlement Period of that Trading Day, Participating Transmission Owners will notify the ISO, via e-mail of an electronic spreadsheet or other means established by the ISO, of the amounts of transmission capacity to reserve for its transmission service customers under Existing Contracts at particular Inter-Zonal Interfaces. Upon receiving this information, the ISO will, by 9:00 am, calculate the Firm Transmission Rights available on each Inter-Zonal Interface after taking into account transfer capabilities and Existing Contract transmission capacity reservations, and then publish adjusted scheduling rights for Scheduling Coordinators scheduling the use of Firm Transmission Rights and Existing Contract rights. After publishing the adjusted scheduling rights for Existing Contract rights and Firm Transmission Rights, Scheduling Coordinators may submit contract usage templates for validation by the ISO prior to the ISO's deadline for receiving Preferred Day-Ahead Schedules.

SP 3.2.6 By 10:00 am, One Day Ahead

By 10:00 am on the day ahead of the Trading Day (for example, by 10:00 am on Tuesday for the Wednesday Trading Day), the following information flows for each Settlement Period of the Trading Day will be required to take place:

- (a) SCs will provide, via WEnet, the ISO with forecasts of their Direct Access Demand by UDC Service Area;
- (b) the ISO will publish, via WEnet, an updated forecast of system Demands and of the Ancillary Services requirements; and
- (c) the ISO will validate (in accordance with the SBP) the information submitted above by SCs and UDCs.

SP 3.2.6.1 Actions by Scheduling Coordinators and the ISO

By 10:00 am on the day ahead of the Trading Day (for example, by 10:00 am on Tuesday for the Wednesday Trading Day) and for each Settlement Period of that Trading Day (see SP 3.2.6.2 for information on the pre-validation performed at ten (10) minutes prior to the 10:00 am deadline):

- (a) Scheduling Coordinators will submit their Preferred Day-Ahead Schedules to the ISO;
- (b) Scheduling Coordinators will submit, as part of their Preferred Day-Ahead Schedules, their Adjustment Bids, if any, to the ISO;
- (c) Scheduling Coordinators will submit their Ancillary Services bids, if any, to the ISO in accordance with Section 8;
- (d) Scheduling Coordinators will submit their schedules for self-provided Ancillary Services, if any, to the ISO in accordance with the Appendix M and Section 2.5;
- (e) the ISO will validate all Scheduling Coordinator submitted Preferred Day-Ahead Schedules for Energy and Adjustment Bids and may assist Scheduling Coordinators to resolve mismatches in scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades in accordance with the procedure described in SP 3.2.6.4;
- (f) the ISO will validate all Scheduling Coordinator submitted schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which were part of their Preferred Day-Ahead Schedules;
- (g) the ISO will validate all contract usage templates received from Scheduling Coordinators for scheduled uses of Existing Contract rights and Firm Transmission Rights;
- (h) the ISO will validate that all Scheduling Coordinator submitted Preferred Day-Ahead Schedules are compatible with the RMR requirements of which Scheduling Coordinators were notified for that Trading Day and with the Scheduling Coordinators' elected options for delivering the required Energy;
- (i) the ISO will start the first iteration of Inter-Zonal Congestion Management process as described in Section 27.1.1; and
- (j) the ISO will start the Ancillary Services bid evaluation process as described in Section 8.

SP 3.2.6.2 Pre-validation

At 10 minutes prior to the deadline for submittal of the Preferred Day-Ahead Schedules, Adjustment Bids, schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids (the "submittal"), the ISO shall conduct a pre-validation of the stage two validation described in Section 30.4. The purpose of this is to allow the Scheduling Coordinators, particularly those involved in the Inter-Scheduling Coordinator Energy Trades, to identify and resolve any validation

problems. The ISO will immediately communicate the results of each Scheduling Coordinator's pre-validation to that Scheduling Coordinator via WEnet.

SP 3.2.6.3 Invalidation

Except with respect to invalidated contract usage associated with Existing Contract rights or Firm Transmission Rights, invalidation of the submittal for any Settlement Period results in rejection of the submittal for that Settlement Period. Scheduling Coordinators will be notified of any invalid contract usage via an invalidated contract usage template issued, via the WEnet, by the ISO. Invalidation of contract usage will not cause the rejection of the Scheduling Coordinator's submittal; instead, invalid contract usage will be treated as new firm uses of ISO transmission service without the priorities and protections afforded the scheduled use of Existing Contract rights and Firm Transmission Rights. During the initial operations of the ISO, the ISO may assist Scheduling Coordinators to resolve mismatches in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades contained in their Preferred Schedules in accordance with SP 3.2.6.4. Except with respect to contract usage templates (for which Scheduling Coordinators can check whether or not their submittal will pass the ISO's validation checks between 9:00 am and 10:00 am), Scheduling Coordinators may check at any time prior to 10:00 am whether or not their submittal will pass the ISO's validation checks at 10:00 am. It is the responsibility of the Scheduling Coordinators to perform such checks since Preferred Day-Ahead Schedules, Adjustment Bids, Schedules of self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which are invalidated cannot be resubmitted after 10:00 am for the Day-Ahead Market, except that, during the initial period of ISO operations, the ISO will allow resubmission of Preferred Schedules which have mismatches in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades. The ISO will immediately communicate the results of each Scheduling Coordinator's 10:00 am validation to that Scheduling Coordinator via WEnet. If the usage or sum of the usages associated with an Existing Contract results in the contract being over-scheduled, the usages will be adjusted such that a usage in excess of the Existing Contract rights will be considered a new firm use (NFU) and will be exposed to Congestion charges.

SP 3.2.6.4 Inter-Scheduling Coordinator Energy Trades - Mismatches

During the initial period of ISO operations, if the ISO detects a mismatch in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades, the ISO will promptly notify both the receiving and sending Scheduling Coordinators that a mismatch exists and will specify the time, which will allow them approximately one half-hour, by which they may submit modified Schedules which resolve the mismatch. If the Scheduling Coordinators are unable to resolve the mismatch as to quantities in the allotted time and provided there is no dispute as to whether the trade occurred or over its location, then the ISO may adjust the Scheduling Coordinators' Schedules in accordance with the following procedure:

- (a) The ISO will determine which Schedule contains the higher scheduled quantity of Energy for the Inter-Scheduling Coordinator Energy Trade and will reduce it so that it is equal to the lower scheduled quantity. However, if the Schedule specifying the higher scheduled quantity of Energy contains only Inter-Scheduling Coordinator Energy Trades, the ISO will increase the Schedule specifying the lower quantity of Energy so that it is equal to the higher scheduled quantity of Energy.

- (b) If there is a dispute between the Scheduling Coordinators as to whether the trade occurred or over its location, the ISO will remove the disputed trade from the Schedules in which it appears.
- (c) As a consequence of the adjustments under (a) or (b) above, the Scheduling Coordinators whose Schedules have been adjusted will no longer have a Balanced Schedule. The ISO will adjust their resources based on the following priority: Demands, exports, imports, Generation, and other Inter-Scheduling Coordinator Energy Trades.
- (d) The adjustments to each Scheduling Coordinator's portfolio will be based on the Adjustment Bids provided by the Scheduling Coordinator.
- (e) The ISO will notify each Scheduling Coordinator whose Schedule has been adjusted as to the adjustment in its Schedule.

SP 3.2.7 By 11:00 am, One Day Ahead

By 11:00 am on the day ahead of the Trading Day (for example, by 11:00 am on Tuesday for the Wednesday Trading Day) and for each Settlement Period of that Trading Day:

- (a) the ISO will complete the first iteration of the Inter-Zonal Congestion Management process described in SP 10 (if Inter-Zonal Congestion does not exist in any Settlement Period of the Trading Day, the scheduling process will continue with the steps at SP 3.2.9);
- (b) the ISO will provide, via WEnet, Suggested Adjusted Day-Ahead Schedules for Energy to all Scheduling Coordinators which submitted Preferred Day-Ahead Schedules at 10:00 am, including the Scheduling Coordinators which it is proposed should, as a result of Inter-Zonal Congestion Management, have their Preferred Day-Ahead Schedules modified;
- (c) the ISO will publish on WEnet the estimated Day-Ahead Usage Charge rate (in \$/MWh of scheduled flow) for Energy transfers between Zones; and
- (d) the ISO will provide, via WEnet, along with the Suggested Adjusted Day-Ahead Schedules, schedules for Ancillary Services to the Scheduling Coordinators which either:
 - (i) submitted Ancillary Services bids and which, as a result, are proposed to supply Ancillary Services; or
 - (ii) submitted schedules to self-provide Ancillary Services and which schedules have been accepted by the ISO.
- (e) the ISO will provide, via WEnet, the available contract capacity template associated with the Scheduling Coordinator's scheduled use of any Existing Contract rights or Firm Transmission Rights. If any derate of an Inter-Zonal Interface has occurred, the ISO will provide, via WEnet, the invalidated usage information template.

SP 3.2.8 By 12:00 Noon, Day Ahead

By 12:00 noon on the day ahead of the Trading Day (for example, by 12:00 noon on Tuesday for the Wednesday Trading Day) and for each Settlement Period of that Trading Day (except where Inter-Zonal Congestion does not exist, in which case, the scheduling process will omit this step):

SP 3.2.8.1 Actions by Scheduling Coordinators and the ISO

- (a) Scheduling Coordinators will submit Revised Day-Ahead Schedules to the ISO, in response to the ISO's Suggested Adjusted Day-Ahead Schedules;
- (b) Scheduling Coordinators will submit, as part of their Revised Day-Ahead Schedules, revised Adjustment Bids (allowing the range of usage to change, but not the prices), if any, to the ISO;
- (c) Scheduling Coordinators will submit revised Ancillary Services bids, if any, to the ISO in accordance with Section 8;
- (d) Scheduling Coordinators will submit their schedules for self-provided Ancillary Services, if any, to the ISO in accordance with Section 8;
- (e) the ISO will validate all Scheduling Coordinator submitted Revised Day-Ahead Schedules for Energy and Adjustment Bids and may assist Scheduling Coordinators to resolve mismatches in scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades in accordance with the same procedure described in SP 3.2.8.4;
- (f) the ISO will validate all Scheduling Coordinator submitted schedules for self-provided Ancillary Services and Ancillary Services bids which were part of their Revised Day-Ahead Schedules;
- (g) the ISO will validate all contract usage templates received from Scheduling Coordinators for scheduled uses of Existing Contract rights and Firm Transmission Rights.
- (h) the ISO will start the second (and final) iteration of the Inter-Zonal Congestion Management process as described in Section 27.1.1;
- (i) the ISO will start the second (and final) iteration of the Ancillary Services bid evaluation process as described in Section 8; and
- (j) the ISO will use the Scheduling Coordinator's Preferred Day-Ahead Schedule in the event the Scheduling Coordinator does not submit a Revised Day-Ahead Schedule. If a Scheduling Coordinator desires to revise only part of its Preferred Day-Ahead Schedule, those portions of the Revised Day-Ahead Schedule must be submitted, including both the removal of any resources in the Preferred Day-Ahead Schedule which are not to be included in the Revised Day-Ahead Schedule and the addition of any resources that were not included in the Preferred Day-Ahead Schedule but that are to be included in the Revised Day-Ahead Schedule. A Scheduling Coordinator's failure to remove such resources will cause the Revised Schedule to be unbalanced, and rejected as such in the ISO's validation process.

SP 3.2.8.2 Pre-validation

At 10 minutes prior to the deadline for submittal of the Revised Day-Ahead Schedules, Adjustment Bids, schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids (the "submittal"), the ISO shall conduct a pre-validation of the stage two validation described in Section 30.4. The purpose of this is to allow the Schedule Coordinators, particularly those involved in Inter-Scheduling Coordinator Energy Trades, to identify and resolve any validation problems. The ISO will immediately communicate the results of the pre-validation of each Schedule Coordinator's submittal to that Scheduling Coordinator via WEnet.

SP 3.2.8.3 Invalidation

Except with respect to invalidated contract usage associated with Existing Contract rights or Firm Transmission Rights, invalidation of the submittal for any Settlement Period results in rejection of the submittal for that Settlement Period. Scheduling Coordinators will be notified of any invalid contract usage via an invalidated contract usage template issued, via the WEnet, by the ISO. Invalidation of contract usage will not cause the rejection of the Scheduling Coordinator's submittal; instead, invalid contract usage will be treated as new firm uses of ISO transmission service without the priorities and protections afforded the scheduled use of Existing Contract rights and Firm Transmission Rights. During the initial operations of the ISO, the ISO may assist Scheduling Coordinators to resolve mismatches in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades in accordance with 3.2.8.4. Except with respect to contract usage templates, Scheduling Coordinators may check at any time prior to 12:00 noon whether or not their submittal will pass the ISO's validation checks (which are undertaken at 12:00 noon). It is the responsibility of the Scheduling Coordinators to perform such checks since Revised Day-Ahead Schedules, Adjustment Bids, schedules of self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids which are invalidated cannot be resubmitted after 12:00 noon for the Day-Ahead Market, except that during the initial period of operations, the ISO will allow resubmission of Schedules to resolve mismatches in the scheduled quantities and locations for Inter-Scheduling Coordinator Energy Trades. The ISO will immediately communicate the results of each Scheduling Coordinator's 12:00 noon validation to that Scheduling Coordinator via WEnet. If the usage or sum of the usages associated with an Existing Contract results in the contract being over-scheduled, the usages will be adjusted such that a usage in excess of the Existing Contract rights will be considered a new firm use (NFU) and will be exposed to Congestion charges.

SP 3.2.8.4 Inter-Scheduling Coordinator Energy Trades - Mismatches

During the initial period of ISO operations, if the ISO detects a mismatch in the scheduled quantities or locations for Inter-Scheduling Coordinator Energy Trades, the ISO will promptly notify both the receiving and sending Scheduling Coordinators that a mismatch exists and will specify the time, which will allow them approximately one half-hour, by which they may submit modified Schedules which resolve the mismatch. If the Scheduling Coordinators are unable to resolve the mismatch as to quantities in the allotted time and provided there is no dispute as to whether the trade occurred or over its location, the ISO may adjust the Scheduling Coordinators' Schedules in accordance with the following procedure:

- (a) The ISO will determine which Schedule contains the higher scheduled quantity of Energy for the Inter-Scheduling Coordinator Energy Trade and will reduce it so that it is equal to the lower scheduled quantity. However, if the Schedule specifying the higher scheduled quantity of Energy contains only Inter-

Scheduling Coordinator Energy Trades, the ISO will increase the Schedule specifying the lower quantity of Energy so that it is equal to the higher scheduled quantity of Energy.

- (b) If there is a dispute between the Scheduling Coordinators as to whether the trade occurred or over its location, the ISO will remove the disputed trade from the Schedules in which it appears.
- (c) As a consequence of the adjustments under (a) or (b) above, the Scheduling Coordinators whose Schedules have been adjusted will no longer have a Balanced Schedule. The ISO will adjust their resources based on the following priority: Demands, exports, imports, Generation, and other Inter-Scheduling Coordinator Energy Trades.
- (d) The adjustments to each Scheduling Coordinator's portfolio will be based on the Adjustment Bids provided by the Scheduling Coordinator.
- (e) The ISO will notify each Scheduling Coordinator whose Schedule has been adjusted as to the adjustment in its Schedule.

SP 3.2.9 By 1:00 pm, Day Ahead

By 1:00 pm on the day ahead of the Trading Day (for example, by 1:00 pm on Tuesday for the Wednesday Trading Day) and for each Settlement Period of that Trading Day:

- (a) the ISO will complete the second iteration, if necessary, of the Inter-Zonal Congestion Management process described in Section 27.1.1;
- (b) the ISO will provide, via WEnet, Final Day-Ahead Schedules to all Scheduling Coordinators which, depending on the existence of Inter-Zonal Congestion, could be:
 - (i) the Preferred Day-Ahead Schedules (when no Congestion was found at 11:00 am and no mismatched Inter-Scheduling Coordinator Energy Trades);
 - (ii) the Revised Day-Ahead Schedules (when no Congestion was found at 1:00 pm and no mismatched Inter-Scheduling Coordinator Energy Trades);
 - (iii) modified Revised Day-Ahead Schedules for those Scheduling Coordinators which had their Revised Day-Ahead Schedules for Energy modified for Inter-Zonal Congestion or mismatches in Inter-Scheduling Coordinator Energy Trades; or
 - (iv) modified Preferred Day-Ahead Schedules for those Scheduling Coordinators which had their Preferred Schedule for Energy modified for Inter-Scheduling Coordinator Energy Trade mismatches;
- (c) the ISO will publish on WEnet the Day-Ahead Usage Charge rate (in \$/MWh of scheduled flow) for Energy transfer between Zones, if any;
- (d) the ISO will provide, via WEnet, as part of the Final Day-Ahead Schedules, schedules for Ancillary Services to the Scheduling Coordinators which either:

- (i) submitted Ancillary Services bids and which, as a result, have been selected to supply Ancillary Services; or
 - (ii) submitted schedules to self-provide Ancillary Services and which schedules have been validated by the ISO; and
 - (iii) specified Inter-Scheduling Coordinator Ancillary Service Trades which have been validated by the ISO; and
- (e) the ISO will coordinate with adjacent Control Areas on the net schedules between the ISO Control Area and such other Control Areas. If the ISO and the operator of an adjacent Control Area have different records with respect to the net schedules, individual Scheduling Coordinator intertie schedules will be examined. If the other Control Area's records are determined to be correct, the ISO will notify the affected Scheduling Coordinator. If the other Control Area Operator's records are in error, no changes will be required by the ISO or affected Scheduling Coordinators. The affected Scheduling Coordinator is required to correct its schedule in the Hour-Ahead Market.

SP 3.2.10 By 1:30 pm, Day Ahead

By 1:30 pm on the day ahead of the Trading Day (for example, by 1:30 pm on Tuesday for the Wednesday Trading Day) and for each Settlement Period of the Trading Day the ISO will publish, via WENet, an updated forecast of system Demands.

SP 3.2.11 Between 1:00 p.m. and 10:00 p.m.

If, at any time after 1:00 p.m. and before 10:00 p.m. of the day prior to the Trading Day, the ISO determines that it requires Ancillary Services in addition to those provided through the Final Day-Ahead Schedules issued under SP 3.2.9, it may procure such additional Ancillary Services by providing to Scheduling Coordinators, via WENet, amended schedules for Ancillary Services that had been bid in the Day-Ahead Market but were not previously selected in the Final Day-Ahead Schedules, and have not been previously 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 schedules shall be provided to the Scheduling Coordinators no later than 10:00 p.m. of the day prior to the Trading Day.

SP 3.3 Hour-Ahead Market

- (a) The Hour-Ahead Market is a "deviations" market in that it represents changes from the Day-Ahead Market commitments already made for each Settlement Period in the Trading Day. The Scheduling Coordinators do not schedule these deviations. Instead, these deviations are calculated by the ISO as the difference between the Final Hour-Ahead Schedules (reflecting updated forecasts of Generation, Demand, external imports/exports and Inter-Scheduling Coordinator Energy Trades) and the Final Day-Ahead Schedules. If a Scheduling Coordinator does not submit a valid Preferred Hour-Ahead Schedule, its Final Day-Ahead Schedule will be deemed to be its Preferred Hour-Ahead Schedule.
- (b) The Hour-Ahead Markets for each Settlement Period of each Trading Day open when the Day-Ahead Market commitments are made for the same Trading Day. Hour-Ahead Market commitments are made one hour ahead of the start of the applicable Settlement Period, at which time the ISO issues the Final Hour-Ahead

Schedules. There is an option in the bid submittal process for a Scheduling Coordinator to submit a Schedule or bid for one Settlement Period of the Trading Day or a set of Schedules and bids for all Settlement Periods of the Trading Day (but only between 1:00 pm and 12:00 midnight the day before).

- (c) For each Hour-Ahead Market of the Trading Day the ISO's validation of Scheduling Coordinators' contract usage templates, associated with Existing Contract rights or Firm Transmission Rights, will be performed. If a derate of an Inter-Zonal Interface has occurred which affects a Scheduling Coordinator's Final Day-Ahead Schedule or Ancillary Service commitments, the ISO will notify the Scheduling Coordinator, via the WEnet, of its available contract capacity. Additionally, the ISO will validate Scheduling Coordinators' scheduled usage against Scheduling Coordinators' contract usage templates and notify Scheduling Coordinators of any invalidated usage. Such validations and notifications associated with contract usage, available contract capacities and invalidated contract usage will occur during the two hours prior to the ISO's deadline for receiving Preferred Hour-Ahead Schedules.

SP 3.3.1 By Two Hours and Fifteen Minutes Ahead

By two hours and fifteen minutes ahead of the Settlement Period (for example, by 9:45 am for the Settlement Period starting at 12:00 noon [or hour ending 1300]) and with respect to that Settlement Period:

SP 3.3.1.1 Actions by Scheduling Coordinators and the ISO

- (a) Scheduling Coordinators will submit their Preferred Hour-Ahead Schedules to the ISO;
- (b) Scheduling Coordinators will submit, as part of their Preferred Hour-Ahead Schedules, their Adjustment Bids, if any, to the ISO;
- (c) Scheduling Coordinators will submit their Ancillary Services bids, if any, to the ISO in accordance with Section 8;
- (d) Scheduling Coordinators will submit their Schedules for self-provided Ancillary Services and Inter-Scheduling Coordinator Ancillary Service Trades, if any, to the ISO in accordance with Section 8;
- (e) the ISO will validate all Scheduling Coordinator submitted Preferred Hour-Ahead Schedules for Energy and Adjustment Bids;
- (f) Scheduling Coordinators will submit contract usage templates for scheduled uses of Existing Contract rights and Firm Transmission Rights in accordance with the Hour-Ahead Market schedule, including usage template changes needed in response to line derations;
- (g) the ISO will validate all contract usage templates received from Scheduling Coordinators for scheduled uses of Existing Contract rights and Firm Transmission Rights;
- (h) the ISO will validate all Scheduling Coordinator submitted Schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service

Trades, and Ancillary Services bids which were part of their Preferred Hour-Ahead Schedules;

- (i) the ISO will start the Inter-Zonal Congestion Management process as described in Section 27.1.1;
- (j) the ISO will start the Ancillary Services bid evaluation process as described in Section 2.5; and
- (k) the ISO will validate that all Scheduling Coordinator submitted Preferred Hour-Ahead Schedules are compatible with the RMR requirements of which Scheduling Coordinators were notified for that Trading Day and with the Scheduling Coordinators' elected options for delivering the required Energy.

SP 3.3.1.2 Pre-validation

At 10 minutes prior to the deadline for submittal of the Preferred Hour-Ahead Schedules, Adjustment Bids, schedules for self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades, and Ancillary Services bids (the "submittal"), the ISO shall conduct a pre-validation of the stage two validation described in Section 30.4. The purpose of this is to allow the Scheduling Coordinators, particularly those involved in the Inter-Scheduling Coordinator Energy Trades, to identify and resolve any validation problems. The ISO will immediately communicate the results of the pre-validation of each Scheduling Coordinator's submittal to that Scheduling Coordinator via WEnet.

SP 3.3.1.3 Invalidation

Except with respect to invalidated contract usage associated with Existing Contract rights or Firm Transmission Rights, invalidation of the submittal results in rejection of the submittal. Scheduling Coordinators will be notified of any invalid contract usage via an invalidated contract usage template issued, via the WEnet, by the ISO. Invalidation of contract usage will not cause the rejection of the Scheduling Coordinator's submittal; instead, invalid contract usage will be treated as new firm uses of ISO transmission service without the priorities and protections afforded the scheduled use of Existing Contract rights and Firm Transmission Rights. Scheduling Coordinators may check at any time prior to two hours and fifteen minutes ahead of the relevant Settlement Period whether or not their submittals will pass the ISO's validation checks (which are undertaken at two hours and fifteen minutes ahead of the Settlement Period). It is the responsibility of Scheduling Coordinators to perform such checks since Preferred Hour-Ahead Schedules, Adjustment Bids, schedules of self-provided Ancillary Services, Inter-Scheduling Coordinator Ancillary Service Trades and Ancillary Services bids which are invalidated cannot be resubmitted for the Hour-Ahead Market after two hours and fifteen minutes ahead of the relevant Settlement Period. The ISO will immediately communicate the results of each Scheduling Coordinator's two hour and fifteen minute ahead validation to that Scheduling Coordinator via WEnet. If the usage or sum of the usages associated with an Existing Contract results in the contract being over-scheduled, the usages will be adjusted such that a usage in excess of the Existing Contract rights will be considered a new firm use (NFU) and will be exposed to Congestion charges.

SP 3.3.2 By One Hour Ahead

By one hour ahead of the Settlement Period (for example, by 11:00 am for the Settlement Period starting at 12:00 noon [or hour ending 1300]) and in respect of that Settlement Period:

- (a) The ISO will use the Scheduling Coordinator's Final Day-Ahead Schedule, without any Day-Ahead Adjustment Bids or Day-Ahead Ancillary Service bids, in the event the Scheduling Coordinator's Preferred Hour-Ahead Schedule fails validation. If a Scheduling Coordinator desires to submit an Hour-Ahead Schedule that is different than its Final Day-Ahead Schedule the Scheduling Coordinator must submit the Hour-Ahead Schedule including the addition or removal of any resources (i.e., for those resources to be removed, a zero value for the hourly MW quantity) in its Final Day-Ahead Schedule that are to be added, or that are not to be included, in the Hour-Ahead Schedule. A Scheduling Coordinator's failure to add or remove such resources will cause the Hour-Ahead Schedule to be unbalanced, and rejected as such in the ISO's validation process.
- (b) the ISO will complete, if necessary, the Inter-Zonal Congestion Management process described in Section 27.1.1;
- (c) the ISO will provide, via WEnet, Final Hour-Ahead Schedules for Energy to the ISO's real-time dispatchers for use under the DP and to all Scheduling Coordinators which, depending on the existence of Inter-Zonal Congestion, could be:
 - (i) the Preferred Hour-Ahead Schedules (when no Congestion was found at one hour ahead); or
 - (ii) modified Preferred Hour-Ahead Schedules for those Scheduling Coordinators which had their Preferred Hour-Ahead Schedules for Energy modified for Inter-Zonal Congestion; and
- (d) the ISO will publish on WEnet the Hour-Ahead Usage Charge rate (in \$/MWh of scheduled flow) for Energy transfers between Zones, if any;
- (e) the ISO will provide, via WEnet, as part of the Final Hour-Ahead Schedules, schedules for Ancillary Services to the ISO's real-time dispatchers and to the Scheduling Coordinators which either:
 - (i) submitted Ancillary Services bids and which, as a result, have been selected to supply Ancillary Services; or
 - (ii) specified Inter-Scheduling Coordinator Ancillary Service Trades, or submitted schedules to self-provide Ancillary Services and which schedules have been validated by the ISO; and
- (f) each Scheduling Coordinator will provide the ISO, via a form and by means of communication specified by the ISO, resource specific information for all Generating Units and Curtailable Demands constituting its System Unit, if any, scheduled or bid into the ISO's Day-Ahead Market and/or Hour-Ahead Market for Ancillary Services.
- (g) the ISO will coordinate with adjacent Control Areas on the net schedules between the ISO Control Area and such other Control Areas. If the ISO and the operator of an adjacent Control Area have different records with respect to the net schedules, individual Scheduling Coordinator intertie schedules will be examined. If the other Control Area operator's records were in error, no changes will be required by the ISO or Scheduling Coordinators. If the other Control Area operator's records are determined to be correct, the ISO will notify the affected Scheduling Coordinator. The ISO will manually adjust the affected Scheduling

Coordinator's schedule to conform with the other Control Area operator's net schedule, in real time, and the affected Scheduling Coordinator will be responsible for managing any resulting Energy imbalance.

[NOT USED]

Appendix Z (Sheets 1171 through 1206)

Rejected by FERC – April 19, 2007 Order (119 FERC ¶ 61,053)

Docket: ER06-700-002 and ER06-700-003

ISO TARIFF APPENDIX AA
SMALL GENERATOR
INTERCONNECTION PROCEDURES (SGIP)

**SMALL GENERATOR
INTERCONNECTION PROCEDURES (SGIP)**

(For Generating Facilities No Larger Than 20 MW)

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SECTION 1. OBJECTIVES, DEFINITIONS, AND APPLICATION.

1.1 Objectives

The objective of this SGIP is to implement FERC's Order No. 2006 setting forth the requirements for Small 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 SGIP. A reference to a Section or an Appendix is a reference to a Section or an Appendix of the ISO Tariff. References to SGIP are to this Protocol or to the stated paragraph of this Protocol.

1.2.2 Special Definitions for this SGIP

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

"10 kW Inverter Process" shall mean the procedure for evaluating an Interconnection Request for a certified inverter-based Small Generating Facility no larger than 10 kW that uses the SGIP Section 2 screens. The application process uses an all-in-one document that includes a simplified Interconnection Request, simplified procedures, and a brief set of terms and conditions. See SGIP Attachment 5.

"Fast Track Process" shall mean the procedure for evaluating an Interconnection Request for a certified Small Generating Facility no larger than 2 MW that includes the SGIP Section 2 screens, customer options meeting, and optional supplemental review.

"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.

"Study Process" shall mean the procedure for evaluating an Interconnection Request that includes the Scoping Meeting, feasibility study, system impact study, and facilities study, as set forth in Section 3 of this SGIP.

1.3 Application

The applicability of this SGIP is set forth in Section 5.7 of the ISO Tariff. As specified in more detail in Section 5.7 of the ISO Tariff, these procedures are applicable to each new Generating Facility with a Generating Facility Capacity of 20 MW or less, or the expansion of an existing Generating Facility with a resultant Generating Facility Capacity of 20 MW or less, that seeks to

interconnect to the ISO Controlled Grid. Any proposed interconnection of a new Generating Facility to a Participating TO's Distribution System will be processed, as applicable, pursuant to the applicable Participating TO's Wholesale Distribution Access Tariff or CPUC Rule 21, or other Local Regulatory Authority requirements of the Participating TO. For any proposed interconnection of a new Generating Facility with a Generating Facility Capacity of 20 MW or less wherein the Interconnection Customer desires the ISO to perform a Deliverability Assessment, the Interconnection Customer shall submit an Interconnection Request to the ISO under the Large Generator Interconnection Procedures in lieu of these Small Generator Interconnection Procedures, as specified in Section 2.8 of this SGIP.

1.3.1 Applicability

- 1.3.1.1 A request to interconnect a certified Small Generating Facility (See Attachments 3 and 4 for description of certification criteria) no larger than 2 MW shall be evaluated under the SGIP Section 2 Fast Track Process. A request to interconnect a certified inverter-based Small Generating Facility no larger than 10 kW shall be evaluated under the Attachment 5 10 kW Inverter Process. A request to interconnect a Small Generating Facility larger than 2 MW but no larger than 20 MW or a Small Generating Facility that does not pass the Fast Track Process or the 10 kW Inverter Process shall be evaluated under the Study Process set forth in Section 3 of this SGIP.
- 1.3.1.2 Neither these procedures nor the requirements included hereunder apply to Small Generating Facilities interconnected or approved for interconnection prior to 60 Business Days after the effective date of these procedures.
- 1.3.1.3 Prior to submitting its Interconnection Request (Attachment 2), the Interconnection Customer may ask the ISO's interconnection contact employee or office whether the proposed interconnection is subject to these procedures. The ISO shall respond within 15 Business Days.
- 1.3.1.4 Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. The Federal Energy Regulatory Commission expects all transmission providers, market participants, and Interconnection Customers interconnected with electric systems to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.
- 1.3.1.5 References in these procedures to interconnection agreement are to the Small Generator Interconnection Agreement (SGIA).

1.3.2 Pre-Application

The ISO shall designate an employee or office from which information on the application process and on an Affected System can be obtained through informal requests from the Interconnection Customer presenting a proposed project for a specific site. The name, telephone number, and e-mail address of such contact employee or office shall be made available on the ISO's Internet web site. The ISO Controlled Grid information provided to the Interconnection Customer should include relevant system studies, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the ISO Controlled Grid, to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements. The ISO shall comply with reasonable requests for such information.

1.3.3 Interconnection Request

The Interconnection Customer shall submit its Interconnection Request to the ISO, together with the processing fee or deposit specified in the Interconnection Request. The Interconnection Request shall be date- and time-stamped upon receipt. The original date and time stamp applied to the Interconnection Request at the time of its original submission shall be accepted as the qualifying date- and time-stamp for the purposes of any timetable in these procedures. The Interconnection Customer shall be notified of receipt by the ISO within three (3) Business Days of receiving the Interconnection Request. The ISO shall notify the Interconnection Customer within ten (10) Business Days of the receipt of the Interconnection Request as to whether the

Interconnection Request is complete or incomplete. If the Interconnection Request is incomplete, the ISO shall provide a notice that the Interconnection Request is incomplete, along with a written list detailing all information that must be provided to complete the Interconnection Request. The Interconnection Customer will have ten (10) Business Days after receipt of the notice to submit the listed information or to request an extension of time to provide such information. If the Interconnection Customer does not provide the listed information or a request for an extension of time within the deadline, the Interconnection Request will be deemed withdrawn. An Interconnection Request will be deemed complete upon submission of the listed information to the ISO.

1.3.4 Modification of the Interconnection Request

Any modification to machine data or equipment configuration, or to the interconnection site of the Small Generating Facility not agreed to in writing by the ISO and the Interconnection Customer may be deemed a withdrawal of the Interconnection Request and may require submission of a new Interconnection Request, unless proper notification of each Party by the other and a reasonable time to cure the problems created by the changes are undertaken.

1.3.5 Site Control

Documentation of site control must be submitted with the Interconnection Request. Site control may be demonstrated through:

1.3.5.1 Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Small Generating Facility;

1.3.5.2 An option to purchase or acquire a leasehold site for such purpose; or

1.3.5.3 An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for such purpose.

1.3.6 Queue Position

The ISO shall assign a Queue Position based upon the date- and time- stamp of the Interconnection Request. The Queue Position of each Interconnection Request will be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection. The ISO shall maintain a single queue for the ISO Control Area. At the ISO's option, in coordination with the applicable Participating TO, Interconnection Requests may be studied serially or in clusters for the purpose of the system impact study.

1.3.7 Interconnection Requests Submitted Prior to the Effective Date of the SGIP

Nothing in this SGIP affects an Interconnection Customer's Queue Position assigned before the effective date of this SGIP. The Parties agree to complete work on any interconnection study agreement executed prior the effective date of this SGIP in accordance with the terms and conditions of that interconnection study agreement. Any new studies or other additional work will be completed pursuant to this SGIP.

1.3.8 Request for Deliverability Assessment

An Interconnection Customer seeking to interconnect to the ISO Controlled Grid that desires to have a Deliverability Assessment performed for the Small Generating Facility shall be required to have its Interconnection Request processed under the Large Generator Interconnection Procedures (LGIP) or ISO Tariff Appendix W, as applicable.

SECTION 2. FAST TRACK PROCESS

2.1 Applicability

The Fast Track Process is available to an Interconnection Customer proposing to interconnect its Small Generating Facility with the ISO Controlled Grid if the Small Generating Facility is no larger than 2 MW and if the Interconnection Customer's proposed Small Generating Facility meets the codes, standards, and certification requirements of Attachments 3 and 4 of these procedures, or the applicable Participating TO has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

2.2 Initial Review

Within 15 Business Days after the ISO notifies the Interconnection Customer it has received a complete Interconnection Request, the applicable Participating TO shall perform an initial review using the screens set forth below, shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the Participating TO's determinations under the screens.

2.2.1 Screens

- 2.2.1.1 The proposed Small Generating Facility's Point of Interconnection must be on a portion of the Participating TO's Distribution System that is subject to the ISO Tariff.
- 2.2.1.2 For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Small Generating Facility, on the circuit shall not exceed 15% of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Participating TO's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.
- 2.2.1.3 For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW³.
- 2.2.1.4 The proposed Small Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.
- 2.2.1.5 The proposed Small Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability.

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³ A spot Network is a type of distribution system found within modern commercial buildings to provide high reliability of service to a single customer. (Standard Handbook for Electrical Engineers, 11th edition, Donald Fink, McGraw Hill Book Company)

2.2.1.6 Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection to limit the potential for creating over-voltages on the Participating TO's electric power system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result/Criteria
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass screen
Three-phase, four wire	Effectively-grounded 3 phase or Single-phase, line-to-neutral	Pass screen

2.2.1.7 If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW.

2.2.1.8 If the proposed Small Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer.

2.2.1.9 The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection).

2.2.1.10 No construction of facilities by the Participating TO on its own system shall be required to accommodate the Small Generating Facility.

2.2.2 If the proposed interconnection passes the screens, the Interconnection Request shall be approved and the Participating TO will provide the Interconnection Customer an executable interconnection agreement within five Business Days after the determination.

2.2.3 If the proposed interconnection fails the screens, but the Participating TO determines that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the Participating TO shall provide the Interconnection Customer an executable interconnection agreement within five Business Days after the determination.

2.2.4 If the proposed interconnection fails the screens, but the Participating TO does not or cannot determine from the initial review that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer is willing to consider minor modifications or further study, the Participating TO shall provide the Interconnection Customer with the opportunity to attend a customer options meeting.

2.3 Customer Options Meeting

If the Participating TO determines the Interconnection Request cannot be approved without minor modifications at minimal cost; or a supplemental study or other additional studies or actions; or at significant cost to address safety, reliability, or power quality problems, within the five Business Day period after the determination, the Participating TO shall notify the Interconnection Customer and provide copies of all data and analyses underlying its conclusion. Within ten Business Days of the Participating TO's determination, the Participating TO shall offer to convene a customer options meeting with the Participating TO to review possible Interconnection Customer facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the Small Generating Facility to be connected safely and reliably. At the time of notification of the Participating TO's determination, or at the customer options meeting, the Participating TO shall:

2.3.1 Offer to perform facility modifications or minor modifications to the Participating TO's electric system (e.g., changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost to make such modifications to the Participating TO's electric system; or

2.3.2 Offer to perform a supplemental review if the Participating TO concludes that the supplemental review might determine that the Small Generating Facility could continue to qualify for interconnection pursuant to the Fast Track Process, and provide a non-binding good faith estimate of the costs of such review; or

2.3.3 Obtain the Interconnection Customer's agreement to continue evaluating the Interconnection Request under the SGIP Section 3 Study Process.

2.4 Supplemental Review

If the Interconnection Customer agrees to a supplemental review, the Interconnection Customer shall agree in writing within 15 Business Days of the offer, and submit a deposit for the estimated costs. The Interconnection Customer shall be responsible for the Participating TO's actual costs for conducting the supplemental review. The Interconnection Customer must pay any review costs that exceed the deposit within 20 Business Days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the Participating TO will return such excess within 20 Business Days of the invoice without interest.

2.4.1 Within ten Business Days following receipt of the deposit for a supplemental review, the Participating TO will determine if the Small Generating Facility can be interconnected safely and reliably.

2.4.1.1 If so, the Participating TO shall forward an executable interconnection agreement to the Interconnection Customer within five Business Days.

2.4.1.2 If so, and Interconnection Customer facility modifications are required to allow the Small Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under these procedures, the Participating TO shall forward an executable interconnection agreement to the Interconnection Customer within five Business Days after confirmation that the Interconnection Customer has agreed to make the necessary changes at the Interconnection Customer's cost.

- 2.4.1.3 If so, and minor modifications to the Participating TO's electric system are required to allow the Small Generating Facility to be interconnected consistent with safety, reliability, and power quality standards under the Fast Track Process, the Participating TO shall forward an executable interconnection agreement to the Interconnection Customer within ten Business Days that requires the Interconnection Customer to pay the costs of such system modifications prior to interconnection.
- 2.4.1.4 If not, the Interconnection Request will continue to be evaluated under the SGIP Section 3 Study Process.

SECTION 3. STUDY PROCESS

3.1 Applicability

The Study Process shall be used by an Interconnection Customer proposing to interconnect its Small Generating Facility to the ISO Controlled Grid if the Small Generating Facility (1) is larger than 2 MW but no larger than 20 MW, (2) is not certified, or (3) is certified but did not pass the Fast Track Process or the 10 kW Inverter Process.

3.1.1 Centralized Study Process

- 3.1.1.1 The ISO will be the single point of contact for Interconnection Customer.
- 3.1.1.2 The ISO will be the central point of coordination to involve any Affected Systems.
- 3.1.1.3 The ISO will collect and disburse monies received from Interconnection Customers.
- 3.1.1.4 The ISO will execute interconnection study agreements. 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 small generator 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 study results and final study report must be approved by the ISO.

3.2 Scoping Meeting

- 3.2.1 A Scoping Meeting will be held within ten (10) Business Days after the Interconnection Request is deemed complete, or as otherwise mutually agreed to by the Parties. The ISO, applicable Participating TO, and the Interconnection Customer will bring to the meeting personnel, including system engineers and other resources as may be reasonably required to accomplish the purpose of the meeting.
- 3.2.2 The purpose of the Scoping Meeting is to discuss the Interconnection Request and review existing studies relevant to the Interconnection Request. The Parties shall further discuss whether the ISO should conduct, or caused to be performed, a feasibility study or proceed directly to a system impact study, or a facilities study, or an interconnection agreement. If the Parties agree that a feasibility study should be performed, the ISO shall provide the Interconnection Customer, as soon as possible, but not later than five (5) Business Days after the Scoping Meeting, a feasibility study agreement (Attachment 6) including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

3.2.3 The Scoping Meeting may be omitted by mutual agreement. In order to remain in consideration for interconnection, an Interconnection Customer who has requested a feasibility study must return the executed feasibility study agreement within fifteen (15) Business Days. If the Parties agree not to perform a feasibility study, the ISO shall provide the Interconnection Customer, no later than ~~five~~ (5) Business Days after the Scoping Meeting, a system impact study agreement (Attachment 7) including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

3.3 Feasibility Study

3.3.1 The feasibility study shall identify any potential adverse system impacts or financial impacts, if any, on Local Furnishing Bonds that would result from the interconnection of the Small Generating Facility.

- 3.3.2 A deposit of the lesser of 50 percent of the good faith estimated feasibility study costs or earnest money of \$1,000 will be required from the Interconnection Customer.
 - 3.3.3 The scope of, and cost responsibilities for, the feasibility study are described in the attached feasibility study agreement.
 - 3.3.4 If the feasibility study shows no potential for adverse system impacts and financial impacts on Local Furnishing Bonds, the ISO shall send the Interconnection Customer a facilities study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study. If no additional facilities are required, the Participating TO shall send the Interconnection Customer an executable interconnection agreement within ~~five~~ (5) Business Days.
 - 3.3.5 If the feasibility study shows the potential for adverse system impacts or financial impacts on Local Furnishing Bonds, the review process shall proceed to the appropriate system impact study(s).
- 3.4 System Impact Study
- 3.4.1 A system impact study shall identify and detail the electric system impacts, including Local Furnishing Bond impacts, that would result if the proposed Small Generating Facility were interconnected without project modifications or electric system modifications, focusing on the adverse system impacts identified in the feasibility study, or to study potential impacts, including but not limited to those identified in the Scoping Meeting. A system impact study shall evaluate the impact of the proposed interconnection on the reliability of the electric system.
 - 3.4.2 If no ISO Controlled Grid system impact study is required, but potential electric power Distribution System adverse system impacts or Local Furnishing Bond impacts are identified in the Scoping Meeting or shown in the feasibility study, a Distribution System impact study must be performed by the applicable Participating TO. The applicable Participating TO shall send the Interconnection Customer a Distribution System impact study agreement within fifteen (15) Business Days of transmittal of the feasibility study report, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or following the Scoping Meeting if no feasibility study is to be performed.
 - 3.4.3 In instances where the feasibility study or the Distribution System impact study shows potential for ISO Controlled Grid adverse system impacts or Local Furnishing Bond adverse impacts, within five (5) Business Days following transmittal of the feasibility study report, the ISO shall send the Interconnection Customer a system impact study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, if such a study is required.
 - 3.4.4 If an ISO Controlled Grid system impact study is not required, but electric power Distribution System adverse system impacts are shown by the feasibility study to be possible and no Distribution System impact study has been conducted, the applicable Participating TO shall send the Interconnection Customer a Distribution System impact study agreement.

- 3.4.5 If the feasibility study shows no potential for ISO Controlled Grid, Local Furnishing Bond, or Distribution System adverse system impacts, the ISO shall send the Interconnection Customer either a facilities study agreement (Attachment 8), including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or the applicable Participating TO shall send an executable interconnection agreement, as applicable.
 - 3.4.6 In order to remain under consideration for interconnection, the Interconnection Customer must return executed system impact study agreements, if applicable, within thirty (30) **Business Days**.
 - 3.4.7 A deposit of the good faith estimated costs for each system impact study will be required from the Interconnection Customer.
 - 3.4.8 The scope of, and cost responsibilities for, a system impact study are described in the attached system impact study agreement.
 - 3.4.9 Where transmission systems and Distribution Systems have separate owners, such as is the case with transmission-dependent utilities ("TDUs") – whether investor-owned or not – the Interconnection Customer may apply to the nearest transmission provider (transmission owner, Regional Transmission Operator, or independent system operator) providing transmission service to the TDU to request project coordination. Affected Systems shall participate in the study and provide all information necessary to prepare the study.
- 3.5 Facilities Study
- 3.5.1 Once the required system impact study(s) is completed, a system impact study report shall be prepared and transmitted to the Interconnection Customer along with a facilities study agreement within five (5) Business Days, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the facilities study. In the case where one or both impact studies are determined to be unnecessary, a notice of the fact shall be transmitted to the Interconnection Customer within the same timeframe.
 - 3.5.2 In order to remain under consideration for interconnection, or, as appropriate, in the ISO's interconnection queue, the Interconnection Customer must return the executed facilities study agreement or a request for an extension of time within thirty (30) **Business Days**.
 - 3.5.3 The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s).
 - 3.5.4 **[INTENTIONALLY LEFT BLANK]**

- 3.5.5 A deposit of the good faith estimated costs for the facilities study will be required from the Interconnection Customer.
- 3.5.6 The scope of, and cost responsibilities for, the facilities study are described in the attached facilities study agreement.
- 3.5.7 Within 30 Business Days after completion of the facilities study, the Interconnection Customer shall take one of the following actions: (i) agree to pay for Interconnection Facilities and Upgrades identified in the facilities study and request that the Participating TO tender an executable interconnection agreement, (ii) withdraw its Interconnection Request, or (iii) request that the Participating TO tender an executable interconnection agreement despite its disagreement with the costs therein. If requested, the Participating TO shall provide the Interconnection Customer an executable interconnection agreement within ~~five~~ (5) Business Days. Upon option (iii) herein, the Interconnection Customer may request that the interconnection agreement be filed unilaterally at FERC.
- 3.5.8 **[INTENTIONALLY LEFT BLANK]**
- 3.5.9 Engineering and Procurement Agreement
Prior to executing an SGIA, 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 SGIP. 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 4. PROVISIONS THAT APPLY TO ALL INTERCONNECTION REQUESTS

4.1 Reasonable Efforts

The ISO shall make reasonable efforts to meet all time frames provided in these procedures unless the ISO and the Interconnection Customer agree to a different schedule. If the ISO cannot meet a deadline provided herein, it shall notify the Interconnection Customer, explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

4.2 Disputes

4.2.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this section.

4.2.2 In the event of a dispute, either Party shall provide the other Party with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.

4.2.3 If the dispute has not been resolved within two (2) Business Days after receipt of the Notice, either Party may contact FERC's Dispute Resolution Service (DRS) for assistance in resolving the dispute.

4.2.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. DRS can be reached at 1-877-337-2237 or via the internet at <http://www.ferc.gov/legal/adr.asp>.

4.2.5 Each Party agrees to conduct all negotiations in good faith and will be responsible for one-half of any costs paid to neutral third-parties.

4.2.6 If neither Party elects to seek assistance from the DRS, or if the attempted dispute resolution fails, then either Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of this SGIP.

4.3 Interconnection Metering

Any metering necessitated by the use of the Small Generating Facility shall be installed at the Interconnection Customer's expense in accordance with Federal Energy Regulatory Commission, state, or local regulatory requirements or the ISO's specifications.

4.4 Commissioning

Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards. The ISO and applicable Participating TO must be given at least five (5) Business Days written notice, or as otherwise mutually agreed to by the Parties, of the tests and may be present to witness the commissioning tests.

4.5. Confidentiality

4.5.1 Confidential Information shall mean any confidential and/or proprietary information provided by one Party to another Party that is clearly marked or otherwise designated "Confidential." For purposes of this SGIP, all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such.

- 4.5.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Parties and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce this SGIP. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under this SGIP, or to fulfill legal or regulatory requirements.
- 4.5.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Parties as it employs to protect its own Confidential Information.
- 4.5.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.
- 4.5.3 Notwithstanding anything in this section to the contrary, and pursuant to 18 CFR § 1b.20, if FERC, 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 SGIP, the Party shall provide the requested information to FERC, within the time provided for in the request for information. In providing the information to FERC, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by FERC 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. The Party shall notify the other Parties when it is notified by FERC 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 CFR § 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.
- 4.6 Comparability
The ISO shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this SGIP. The ISO shall use the same reasonable efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Small Generating Facility is owned or operated by the applicable Participating TO, its subsidiaries or Affiliates, or others.
- 4.7 Record Retention
The ISO shall maintain for three (3) years records, subject to audit, of all Interconnection Requests received under these procedures, the times required to complete Interconnection Request approvals and disapprovals, and justification for the actions taken on the Interconnection Requests.
- 4.8 Interconnection Agreement
The Participating TO, with the ISO's review and concurrence, shall issue a SGIA to the Interconnection Customer. After receiving an interconnection agreement from the Participating TO, the Interconnection Customer shall have thirty (30) Business Days or another mutually agreeable timeframe to sign and return the interconnection agreement, or request that the ISO and Participating TO file an unexecuted interconnection agreement with the Federal Energy Regulatory Commission. If the Interconnection Customer does not sign the interconnection agreement, or ask that it be filed unexecuted by the ISO and Participating TO within thirty (30) Business Days, the Interconnection Request shall be deemed withdrawn. After the

interconnection agreement is signed by the Parties, the interconnection of the Small Generating Facility shall proceed under the provisions of the interconnection agreement.

4.9 Coordination with Affected Systems

The ISO shall coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System operators and, if possible, include those results (if available) in its applicable interconnection study within the time frame specified in these procedures. The ISO will include such Affected System operators in all meetings held with the Interconnection Customer as required by these procedures. 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. A transmission provider, 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.

4.10 Capacity of the Small Generating Facility

4.10.1 If the Interconnection Request is for an increase in capacity for an existing Small Generating Facility, the Interconnection Request shall be evaluated on the basis of the new total capacity of the Small Generating Facility.

4.10.2 If the Interconnection Request is for a Small Generating Facility that includes multiple energy production devices at a site for which the Interconnection Customer seeks a single Point of Interconnection, the Interconnection Request shall be evaluated on the basis of the aggregate capacity of the multiple devices.

4.10.3 The Interconnection Request shall be evaluated using the maximum rated capacity of the Small Generating Facility.

Attachment 1

[INTENTIONALLY LEFT BLANK]

Attachment 2

**SMALL GENERATOR INTERCONNECTION REQUEST
(Application Form)**

California Independent System Operator

Designated Contact Person: _____

Address: _____

Telephone Number: _____

Fax: _____

E-Mail Address: _____

An Interconnection Request is considered complete when it provides all applicable and correct information required below. Per SGIP Section 1.3.5, documentation of Site Control must be submitted with the Interconnection Request.

Preamble and Instructions

Request for Deliverability Assessment – Yes ___ No ___

An Interconnection Customer seeking to interconnect to the ISO Controlled Grid that desires to have a Deliverability Assessment performed for the Small Generating Facility is required to have its Interconnection Request processed under the Large Generator Interconnection Procedures (LGIP) or ISO Tariff Appendix W, as applicable.

An Interconnection Customer who requests a Federal Energy Regulatory Commission jurisdictional interconnection must submit this Interconnection Request by hand delivery, mail, e-mail, or fax to the ISO.

Processing Fee or Deposit:

If the Interconnection Request is submitted under the Fast Track Process, the non-refundable processing fee is \$500.

If the Interconnection Request is submitted under the Study Process, whether a new submission or an Interconnection Request that did not pass the Fast Track Process, the Interconnection Customer shall submit to the ISO a deposit not to exceed \$1,000 towards the cost of the feasibility study.

Interconnection Customer Information

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name: _____

Contact Person: _____

Mailing Address: _____

City: _____ State: _____ Zip: _____

Facility Location (if different from above): _____

Telephone (Day): _____ Telephone (Evening): _____

Fax: _____ E-Mail Address: _____

Alternative Contact Information (if different from the Interconnection Customer)

Contact Name: _____

Title: _____

Address: _____

Telephone (Day): _____ Telephone (Evening): _____

Fax: _____ E-Mail Address: _____

Application is for:

_____ New Small Generating Facility

_____ Capacity addition to Existing Small Generating Facility

If capacity addition to existing facility, please describe: _____

Will the Small Generating Facility be used for any of the following?

Net Metering? Yes ___ No ___

To Supply Power to the Interconnection Customer? Yes ___ No ___

To Supply Power to Others? Yes ___ No ___

For installations at locations with existing electric service to which the proposed Small Generating Facility will interconnect, provide:

(Local Electric Service Provider*)

(Existing Account Number*)

[*To be provided by the Interconnection Customer if the local electric service provider is different from the Participating TO]

Contact Name: _____

Title: _____

Address: _____

Telephone (Day): _____ Telephone (Evening): _____

Fax: _____ E-Mail Address: _____

Requested Point of Interconnection: _____

Interconnection Customer's Requested In-Service Date: _____

Small Generating Facility Information

Data apply only to the Small Generating Facility, not the Interconnection Facilities.

Energy Source: Solar Wind Hydro Hydro Type (e.g. Run-of-River): _____
 Diesel Natural Gas Fuel Oil Other (state type) _____

Prime Mover: Fuel Cell Recip Engine Gas Turb Steam Turb
 Microturbine PV Other

Type of Generator: Synchronous Induction Inverter

Generator Nameplate Rating: _____ kW (Typical) Generator Nameplate kVAR: _____

Interconnection Customer or Customer-Site Load: _____ kW (if none, so state)

Typical Reactive Load (if known): _____

Maximum Physical Export Capability Requested: _____ kW

List components of the Small Generating Facility equipment package that are currently certified:

Equipment Type	Certifying Entity
1. _____	_____
2. _____	_____
3. _____	_____
4. _____	_____
5. _____	_____

Is the prime mover compatible with the certified protective relay package? Yes No

Generator (or solar collector)

Manufacturer, Model Name & Number: _____

Version Number: _____

Nameplate Output Power Rating in kW: (Summer) _____ (Winter) _____

Nameplate Output Power Rating in kVA: (Summer) _____ (Winter) _____

Individual Generator Power Factor

Rated Power Factor: Leading: _____ Lagging: _____

Total Number of Generators in wind farm to be interconnected pursuant to this

Interconnection Request: _____ Elevation: _____ Single phase Three phase

Inverter Manufacturer, Model Name & Number (if used): _____

List of adjustable set points for the protective equipment or software: _____

Note: A completed Power Systems Load Flow data sheet must be supplied with the Interconnection Request.

Small Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: _____ Instantaneous _____ or RMS? _____

Harmonics Characteristics: _____

Start-up requirements: _____

Small Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: _____

(*) Neutral Grounding Resistor (If Applicable): _____

Synchronous Generators:

Direct Axis Synchronous Reactance, X_d : _____ P.U.
Direct Axis Transient Reactance, X'_d : _____ P.U.
Direct Axis Subtransient Reactance, X''_d : _____ P.U.
Negative Sequence Reactance, X_2 : _____ P.U.
Zero Sequence Reactance, X_0 : _____ P.U.
KVA Base: _____
Field Volts: _____
Field Amperes: _____

Induction Generators:

Motoring Power (kW): _____
 I_2^2t or K (Heating Time Constant): _____
Rotor Resistance, R_r : _____
Stator Resistance, R_s : _____
Stator Reactance, X_s : _____
Rotor Reactance, X_r : _____
Magnetizing Reactance, X_m : _____
Short Circuit Reactance, X_d'' : _____
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: Please contact the ISO prior to submitting the Interconnection Request to determine if the specified information above is required.

Excitation and Governor System Data for Synchronous Generators Only

Provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with the regional reliability council criteria. A PSS may be determined to be required by applicable studies. A copy of the manufacturer's block diagram may not be substituted.

Interconnection Facilities Information

Will a transformer be used between the generator and the point of common coupling? ___ Yes ___ No

Will the transformer be provided by the Interconnection Customer? ___ Yes ___ No

Transformer Data (If Applicable, for Interconnection Customer-Owned Transformer):

Is the transformer: ___ single phase ___ three phase? Size: _____ kVA
 Transformer Impedance: _____ % on _____ kVA Base

If Three Phase:

Transformer Primary: _____ Volts _____ Delta _____ Wye _____ Wye Grounded
 Transformer Secondary: _____ Volts _____ Delta _____ Wye _____ Wye Grounded
 Transformer Tertiary: _____ Volts _____ Delta _____ Wye _____ Wye Grounded

Transformer Fuse Data (If Applicable, for Interconnection Customer-Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: _____ Type: _____ Size: _____ Speed: _____

Interconnecting Circuit Breaker (if applicable):

Manufacturer: _____ Type: _____
 Load Rating (Amps): _____ Interrupting Rating (Amps): _____ Trip Speed (Cycles): _____

Interconnection Protective Relays (If Applicable):

If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

	Setpoint Function	Minimum	Maximum
1.	_____	_____	_____
2.	_____	_____	_____
3.	_____	_____	_____
4.	_____	_____	_____
5.	_____	_____	_____
6.	_____	_____	_____

If Discrete Components:

(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer: _____ Type: _____ Style/Catalog No.: _____ Proposed Setting: _____
 Manufacturer: _____ Type: _____ Style/Catalog No.: _____ Proposed Setting: _____
 Manufacturer: _____ Type: _____ Style/Catalog No.: _____ Proposed Setting: _____
 Manufacturer: _____ Type: _____ Style/Catalog No.: _____ Proposed Setting: _____
 Manufacturer: _____ Type: _____ Style/Catalog No.: _____ Proposed Setting: _____

Current Transformer Data (If Applicable):

(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer: _____
Type: _____ Accuracy Class: _____ Proposed Ratio Connection: _____

Manufacturer: _____
Type: _____ Accuracy Class: _____ Proposed Ratio Connection: _____

Potential Transformer Data (If Applicable):

Manufacturer: _____
Type: _____ Accuracy Class: _____ Proposed Ratio Connection: _____

Manufacturer: _____
Type: _____ Accuracy Class: _____ Proposed Ratio Connection: _____

General Information

Enclose copy of site electrical one-line diagram showing the configuration of all Small Generating Facility equipment, current and potential circuits, and protection and control schemes. This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Small Generator Facility is larger than 50 kW. Is One-Line Diagram Enclosed? ___Yes ___No

Enclose copy of any site documentation that indicates the precise physical location of the proposed Small Generating Facility (e.g., USGS topographic map or other diagram or documentation).

Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address) _____

Enclose copy of any site documentation that describes and details the operation of the protection and control schemes. Is Available Documentation Enclosed? ___Yes ___No

Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).
Are Schematic Drawings Enclosed? ___Yes ___No

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request is true and correct.

For Interconnection Customer: _____ Date: _____

Attachment 3

Certification Codes and Standards

IEEE1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

NFPA 70 (2002), National Electrical Code

IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

ANSI C84.1-1995 Electric Power Systems and Equipment – Voltage Ratings (60 Hertz)

IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms
NEMA MG 1-1998, Motors and Small Resources, Revision 3

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

Attachment 4

Certification of Small Generator Equipment Packages

- 1.0 Small Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in SGIP Attachment 3, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.
- 2.0 The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.
- 3.0 Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL.
- 4.0 If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.
- 5.0 Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.
- 6.0 An equipment package does not include equipment provided by the utility.
- 7.0 Any equipment package approved and listed in a state by that state's regulatory body for interconnected operation in that state prior to the effective date of these small generator interconnection procedures shall be considered certified under these procedures for use in that state.

Attachment 5

**Application, Procedures, and Terms and Conditions for Interconnecting
a Certified Inverter-Based Small Generating Facility No
Larger than 10 kW ("10 kW Inverter Process")**

- 1.0 The Interconnection Customer ("Customer") completes the Interconnection Request ("Application") and submits it to the Participating TO ("Company").
- 2.0 The Company acknowledges to the Customer receipt of the Application within three Business Days of receipt.
- 3.0 The Company evaluates the Application for completeness and notifies the Customer within ten Business Days of receipt that the Application is or is not complete and, if not, advises what material is missing.
- 4.0 The Company verifies that the Small Generating Facility can be interconnected safely and reliably using the screens contained in the Fast Track Process in the Small Generator Interconnection Procedures (SGIP). The Company has 15 Business Days to complete this process. Unless the Company determines and demonstrates that the Small Generating Facility cannot be interconnected safely and reliably, the Company approves the Application and returns it to the Customer. Note to Customer: Please check with the Company before submitting the Application if disconnection equipment is required.
- 5.0 After installation, the Customer returns the Certificate of Completion to the Company. Prior to parallel operation, the Company may inspect the Small Generating Facility for compliance with standards which may include a witness test, and may schedule appropriate metering replacement, if necessary.
- 6.0 The Company notifies the Customer in writing that interconnection of the Small Generating Facility is authorized. If the witness test is not satisfactory, the Company has the right to disconnect the Small Generating Facility. The Customer has no right to operate in parallel until a witness test has been performed, or previously waived on the Application. The Company is obligated to complete this witness test within ten Business Days of the receipt of the Certificate of Completion. If the Company does not inspect within ten Business Days or by mutual agreement of the Parties, the witness test is deemed waived.
- 7.0 Contact Information – The Customer must provide the contact information for the legal applicant (i.e., the Interconnection Customer). If another entity is responsible for interfacing with the Company, that contact information must be provided on the Application.
- 8.0 Ownership Information – Enter the legal names of the owner(s) of the Small Generating Facility. Include the percentage ownership (if any) by any utility or public utility holding company, or by any entity owned by either.
- 9.0 UL1741 Listed – This standard ("Inverters, Converters, and Controllers for Use in Independent Power Systems") addresses the electrical interconnection design of various forms of generating equipment. Many manufacturers submit their equipment to a Nationally Recognized Testing Laboratory (NRTL) that verifies compliance with UL1741. This "listing" is then marked on the equipment and supporting documentation.

Application for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10kW

This Application is considered complete when it provides all applicable and correct information required below. Additional information to evaluate the Application may be required.

Processing Fee

A non-refundable processing fee of \$100 must accompany this Application.

Interconnection Customer

Name: _____
Contact Person: _____
Address: _____
City: _____ State: _____ Zip: _____
Telephone (Day): _____ (Evening): _____
Fax: _____ E-Mail Address: _____

Contact (if different from Interconnection Customer)

Name: _____
Address: _____
City: _____ State: _____ Zip: _____
Telephone (Day): _____ (Evening): _____
Fax: _____ E-Mail Address: _____

Owner of the facility (include % ownership by any electric utility): _____

Small Generating Facility Information

Location (if different from above): _____
Electric Service Company: _____
Account Number: _____
Inverter Manufacturer: _____ Model _____
Nameplate Rating: _____ (kW) _____ (kVA) _____ (AC Volts)
Single Phase _____ Three Phase _____
System Design Capacity: _____ (kW) _____ (kVA)
Prime Mover: Photovoltaic Reciprocating Engine Fuel Cell
Turbine Other _____
Energy Source: Solar Wind Hydro Diesel Natural Gas
Fuel Oil Other (describe) _____
Is the equipment UL1741 Listed? Yes No _____
If Yes, attach manufacturer's cut-sheet showing UL1741 listing

Estimated Installation Date: _____ Estimated In-Service Date: _____

The 10 kW Inverter Process is available only for inverter-based Small Generating Facilities no larger than 10 kW that meet the codes, standards, and certification requirements of Attachments 3 and 4 of the Small Generator Interconnection Procedures (SGIP), or the Participating TO has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

List components of the Small Generating Facility equipment package that are currently certified:

	Equipment Type	Certifying Entity
1.	_____	_____
2.	_____	_____
3.	_____	_____
4.	_____	_____
5.	_____	_____

Interconnection Customer Signature

I hereby certify that, to the best of my knowledge, the information provided in this Application is true. I agree to abide by the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return the Certificate of Completion when the Small Generating Facility has been installed.

Signed: _____

Title: _____ Date: _____

Contingent Approval to Interconnect the Small Generating Facility

(For Company use only)

Interconnection of the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return of the Certificate of Completion.

Company Signature: _____

Title: _____ Date: _____

Application ID number: _____

Company waives inspection/witness test? Yes ___ No ___

Small Generating Facility Certificate of Completion

Is the Small Generating Facility owner-installed? Yes _____ No _____

Interconnection Customer: _____

Contact Person: _____

Address: _____

Location of the Small Generating Facility (if different from above):

City: _____ State: _____ Zip Code: _____

Telephone (Day): _____ (Evening): _____

Fax: _____ E-Mail Address: _____

Electrician:

Name: _____

Address: _____

City: _____ State: _____ Zip Code: _____

Telephone (Day): _____ (Evening): _____

Fax: _____ E-Mail Address: _____

License number: _____

Date Approval to Install Facility granted by the Company: _____

Application ID number: _____

Inspection:

The Small Generating Facility has been installed and inspected in compliance with the local building/electrical code of _____

Signed (Local electrical wiring inspector, or attach signed electrical inspection):

Print Name: _____

Date: _____

As a condition of interconnection, you are required to send/fax a copy of this form along with a copy of the signed electrical permit to (insert Company information below):

Name: _____

Company: _____

Address: _____

City _____ State _____ ZIP: _____

Fax: _____

Approval to Energize the Small Generating Facility (For Company use only)

Energizing the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

Company Signature: _____

Title: _____ Date: _____

**Terms and Conditions for Interconnecting an Inverter-Based
Small Generating Facility No Larger than 10kW**

1.0 Construction of the Facility

The Interconnection Customer (the "Customer") may proceed to construct (including operational testing not to exceed two hours) the Small Generating Facility when the Participating TO (the "Company") approves the Interconnection Request (the "Application") and returns it to the Customer.

2.0 Interconnection and Operation

The Customer may operate Small Generating Facility and interconnect with the Company's electric system once all of the following have occurred:

2.1 Upon completing construction, the Customer will cause the Small Generating Facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction, and

2.2 The Customer returns the Certificate of Completion to the Company, and

2.3 The Company has either:

2.3.1 Completed its inspection of the Small Generating Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes. All inspections must be conducted by the Company, at its own expense, within ten Business Days after receipt of the Certificate of Completion and shall take place at a time agreeable to the Parties. The Company shall provide a written statement that the Small Generating Facility has passed inspection or shall notify the Customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place; or

2.3.2 If the Company does not schedule an inspection of the Small Generating Facility within ten business days after receiving the Certificate of Completion, the witness test is deemed waived (unless the Parties agree otherwise); or

2.3.3 The Company waives the right to inspect the Small Generating Facility.

2.4 The Company has the right to disconnect the Small Generating Facility in the event of improper installation or failure to return the Certificate of Completion.

2.5 Revenue quality metering equipment must be installed and tested in accordance with applicable ANSI standards.

3.0 Safe Operations and Maintenance

The Customer shall be fully responsible to operate, maintain, and repair the Small Generating Facility as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

4.0 Access

The Company shall have access to the disconnect switch (if the disconnect switch is required) and metering equipment of the Small Generating Facility at all times. The Company shall provide reasonable notice to the Customer when possible prior to using its right of access.

5.0 Disconnection

The Company may temporarily disconnect the Small Generating Facility upon the following conditions:

- 5.1 For scheduled outages upon reasonable notice.
- 5.2 For unscheduled outages or emergency conditions.
- 5.3 If the Small Generating Facility does not operate in the manner consistent with these Terms and Conditions.
- 5.4 The Company shall inform the Customer in advance of any scheduled disconnection, or as is reasonable after an unscheduled disconnection.

6.0 Indemnification

The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.0 Insurance

The Parties each agree to maintain commercially reasonable amounts of insurance.

8.0 Limitation of Liability

Each party's liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either party be liable to the other party for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under paragraph 6.0.

9.0 Termination

The agreement to operate in parallel may be terminated under the following conditions:

- 9.1 **By the Customer**
By providing written notice to the Company.
- 9.2 **By the Company**
If the Small Generating Facility fails to operate for any consecutive 12 month period or the Customer fails to remedy a violation of these Terms and Conditions.
- 9.3 **Permanent Disconnection**
In the event this Agreement is terminated, the Company shall have the right to disconnect its facilities or direct the Customer to disconnect its Small Generating Facility.
- 9.4 **Survival Rights**
This Agreement shall continue in effect after termination to the extent necessary to allow or require either Party to fulfill rights or obligations that arose under the Agreement.

10.0 Assignment/Transfer of Ownership of the Facility

This Agreement shall survive the transfer of ownership of the Small Generating Facility to a new owner when the new owner agrees in writing to comply with the terms of this Agreement and so notifies the Company.

Attachment 6

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"). Interconnection Customer and ISO each may
be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Small Generating Facility or generating
capacity addition to an existing Small Generating Facility consistent with the Interconnection Request
completed by Interconnection Customer on _____; and

WHEREAS, Interconnection Customer desires to interconnect the Small Generating Facility with the ISO
Controlled Grid; and

WHEREAS, Interconnection Customer has requested the ISO to conduct or cause to be performed a
feasibility study to assess the feasibility of interconnecting the proposed Small Generating Facility with the
ISO Controlled Grid, and of any Affected Systems;

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 or the meanings specified in the Master Definitions Supplement, Appendix A of the ISO Tariff.
- 2.0 The Interconnection Customer elects and the ISO shall conduct or cause to be performed an interconnection feasibility study consistent the standard Small Generator Interconnection Procedures in accordance with the ISO Tariff.
- 3.0 The scope of the feasibility study shall be subject to the assumptions set forth in Attachment A to this Agreement.
- 4.0 The 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 feasibility study and as designated in accordance with the standard Small Generator Interconnection Procedures. If the Interconnection Customer modifies its Interconnection Request, the time to complete the feasibility study may be extended by agreement of the Parties.
- 5.0 In performing the study, the ISO shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the feasibility study.
- 6.0 The feasibility study report shall provide the following analyses for the purpose of identifying any

potential adverse system impacts that would result from the interconnection of the Small Generating Facility as proposed:

- 6.1 Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;
 - 6.2 Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;
 - 6.3 Initial review of grounding requirements and electric system protection;
 - 6.4 preliminary identification of financial impacts, if any, on Local Furnishing Bonds; and
 - 6.5 Description and non-bonding estimated cost of facilities required to interconnect the proposed Small Generating Facility and to address the identified short circuit and power flow issues.
- 7.0 The feasibility study shall model the impact of the Small Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Small Generating Facility is being installed.
- 8.0 The study shall include the feasibility of any interconnection at a proposed project site where there could be multiple potential Points of Interconnection, as requested by the Interconnection Customer and at the Interconnection Customer's cost.
- 9.0 A deposit of the lesser of 50 percent of good faith estimated feasibility study costs or earnest money of \$1,000 shall be required from the Interconnection Customer.
- 10.0 Once the feasibility study is completed, a feasibility study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the feasibility study must be completed and the feasibility study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct a feasibility study.
- 11.0 Any study fees shall be based on the ISO's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.
- 12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 Calendar Days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the ISO shall refund such excess within 30 Calendar Days of the invoice without interest.
- 13.0 Miscellaneous.
- 13.1 Dispute Resolution. Any dispute, or assertion of a claim, arising out of or in connection with this Agreement, shall be resolved in accordance with Section 4.2 of the SGIP.
- 13.2 Confidentiality. Confidential Information shall be treated in accordance with Section 4.5 of the SGIP.
- 13.3 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.

- 13.4 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.
- 13.5 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 Feasibility 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, Attachment, or Appendix means such Article or Section of this Agreement or such Attachment or Appendix to this Agreement, or such Section of the SGIP or such Attachment or Appendix to the SGIP, 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 Section; (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 Governing Law, Regulatory Authority, and Rules. The validity, interpretation and enforcement of this Agreement 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. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.
- 13.7 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.
- 13.8 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 either 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. Termination or default of this 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 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.

- 13.9 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.
- 13.10 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.
- 13.11 Amendment. The Parties may by mutual agreement amend this 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 Agreement by a written instrument duly executed by both of the Parties. Such amendment shall become effective and a part of this 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 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 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 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 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 Agreement may be assigned by a Party only with the written consent of the other Party; provided that a Party may assign this 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 Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of the other Party, for collateral security purposes to aid in providing financing for the 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 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.
- 13.16 Severability. If any provisions or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

13.17 Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties 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 Transmission Provider Participating TO or the ISO be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

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

Signed _____

Name (Printed): _____

Title _____

[Insert name of Interconnection Customer]

Signed _____

Name (Printed): _____

Title _____

**Attachment A to
Feasibility Study Agreement**

Assumptions Used in Conducting the Feasibility Study

The feasibility study will be based upon the information set forth in the Interconnection Request and agreed upon in the Scoping Meeting held on _____:

- 1) Designation of Point of Interconnection and configuration to be studied.

- 2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the ISO.

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"). Interconnection Customer and ISO each may
be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or
generating capacity addition to an existing Small Generating Facility consistent with the Interconnection
Request completed by the Interconnection Customer on _____; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the
ISO Controlled Grid;

WHEREAS, the ISO has completed a feasibility study and provided the results of said study to the
Interconnection Customer (This recital to be omitted if the Parties have agreed to forego the feasibility
study.); and

WHEREAS, the Interconnection Customer has requested the ISO to conduct or cause to be performed a
system impact study(s) to assess the impact of interconnecting the Small Generating Facility with the ISO
Controlled Grid, and of any Affected Systems;

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 or the meanings specified in the Master Definitions Supplement, Appendix A
of the ISO Tariff.
- 2.0 The Interconnection Customer elects and the ISO shall conduct or cause to be performed a
system impact study(s) consistent with the standard Small Generator Interconnection Procedures
in accordance with the ISO Tariff.
- 3.0 The scope of a system impact study shall be subject to the assumptions set forth in Attachment A
to this Agreement.
- 4.0 A system impact study will be based upon the results of the feasibility study and the technical
information provided by Interconnection Customer in the Interconnection Request. 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 system impact study. If the Interconnection Customer modifies its designated Point of
Interconnection, Interconnection Request, or the technical information provided therein is
modified, the time to complete the system impact study may be extended.

- 5.0 A system impact study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, an assessment of the potential magnitude of financial impacts, if any, on Local Furnishing Bonds and a proposed resolution, and grounding reviews, as necessary. A system impact study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement 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. A system impact study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.
- 6.0 A Distribution System impact study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.
- 7.0 Affected Systems may participate in the preparation of a system impact study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon a system impact study that covers potential adverse system impacts on their electric systems, and the ISO has 20 additional Business Days to complete a system impact study requiring review by Affected Systems.
- 8.0 If the ISO uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the system impact study shall consider all generating facilities (and with respect to paragraph 8.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the system impact study is commenced –
- 8.1 Are directly interconnected with the ISO Controlled Grid; or
 - 8.2 Are interconnected with Affected Systems and may have an impact on the proposed interconnection; and
 - 8.3 Have a pending higher queued Interconnection Request to interconnect with the ISO Controlled Grid.
- 9.0 A Distribution System impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 30 Business Days after this Agreement is signed by the Parties. An ISO Controlled Grid system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 45 Business Days after this Agreement is signed by the Parties, or in accordance with the ISO queuing procedures.
- 10.0 A deposit of the equivalent of the good faith estimated cost of a Distribution System impact study and one half the good faith estimated cost of an ISO Controlled Grid system impact study shall be required from the Interconnection Customer.
- 11.0 Any study fees shall be based on the ISO actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.
- 12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 Calendar Days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the ISO shall refund such excess within 30 Calendar Days of the invoice without interest.
- 13.0 Miscellaneous.

- 13.1 Dispute Resolution. Any dispute, or assertion of a claim, arising out of or in connection with this Agreement, shall be resolved in accordance with Section 4.2 of the SGIP.
- 13.2 Confidentiality. Confidential Information shall be treated in accordance with Section 4.5 of the SGIP.
- 13.3 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.
- 13.4 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.
- 13.5 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 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, Attachment, or Appendix means such Article or Section of this Agreement or such Attachment or Appendix to this Agreement, or such Section of the SGIP or such Attachment or Appendix to the SGIP, 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 Section; (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 Governing Law, Regulatory Authority, and Rules. The validity, interpretation and enforcement of this Agreement 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. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.
- 13.7 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.
- 13.8 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 either 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. Termination or default of this 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 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.
- 13.9 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.
- 13.10 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.
- 13.11 Amendment. The Parties may by mutual agreement amend this 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 Agreement by a written instrument duly executed by both of the Parties. Such amendment shall become effective and a part of this 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 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 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 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 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 Agreement may be assigned by a Party only with the written consent of the other Party; provided that a Party may assign this 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 Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of the other Party, for collateral security purposes to aid in providing financing for the 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 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.

- 13.16 Severability. If any provisions or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.
- 13.17 Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties 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 Transmission Provider Participating TO or the ISO be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

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

Signed _____

Name (Printed): _____

Title _____

[Insert name of Interconnection Customer]

Signed _____

Name (Printed): _____

Title _____

**Attachment A to System
Impact Study Agreement**

Assumptions Used in Conducting the System Impact Study

The system impact study shall be based upon the results of the feasibility study, subject to any modifications in accordance with the standard Small Generator Interconnection Procedures, and the following assumptions:

- 1) Designation of Point of Interconnection and configuration to be studied.

- 2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the ISO.

Attachment 8

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"). Interconnection Customer and ISO each may
be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or
generating capacity addition to an existing Small Generating Facility consistent with the Interconnection
Request completed by the Interconnection Customer on _____; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the
ISO Controlled Grid;

WHEREAS, the ISO has completed a 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 a
facilities study to specify and estimate the cost of the equipment, engineering, procurement and
construction work needed to implement the conclusions of the system impact study in accordance with
Good Utility Practice to physically and electrically connect the Small Generating Facility with 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 or the meanings specified in the Master Definitions Supplement, Appendix A of the ISO Tariff.
- 2.0 The Interconnection Customer elects and the ISO shall cause a facilities study consistent with the standard Small Generator Interconnection Procedures to be performed in accordance with the ISO Tariff.
- 3.0 The scope of the facilities study shall be subject to data provided in Attachment A to this Agreement.
- 4.0 The facilities study shall specify and estimate the cost, including, if applicable, the cost of remedial measures that address the financial impacts, if any, on Local Furnishing Bonds, of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s). The facilities study shall also identify (1) the electrical switching configuration of the equipment, including, without limitation, transformer, switchgear, meters, and other station equipment, (2) the nature and estimated cost of the Participating TO's Interconnection Facilities and Upgrades necessary to accomplish the interconnection, and (3) an estimate of the time required to complete the construction and installation of such facilities or for effecting remedial measures that address the financial impacts, if any, on Local Furnishing Bonds.

- 5.0 The ISO may propose to group facilities required for more than one Interconnection Customer in order to minimize facilities costs through economies of scale, but any Interconnection Customer may require the installation of facilities required for its own Small Generating Facility if it is willing to pay the costs of those facilities.
- 6.0 A deposit of the good faith estimated facilities study costs shall be required from the Interconnection Customer.
- 7.0 In cases where Upgrades are required, the facilities study must be completed within 45 Business Days of the receipt of this Agreement. In cases where no Upgrades are necessary, and the required facilities are limited to Interconnection Facilities, the facilities study must be completed within 30 Business Days.
- 8.0 Once the facilities study is completed, a facilities study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the facilities study must be completed and the facilities study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct a facilities study.
- 9.0 Any study fees shall be based on the ISO's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.
- 10.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 Calendar Days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the ISO shall refund such excess within 30 Calendar Days of the invoice without interest.
- 11.0 Miscellaneous.
- 11.1 Dispute Resolution. Any dispute, or assertion of a claim, arising out of or in connection with this Agreement, shall be resolved in accordance with Section 4.2 of the SGIP.
- 11.2 Confidentiality. Confidential Information shall be treated in accordance with Section 4.5 of the SGIP.
- 11.3 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.
- 11.4 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.
- 11.5 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 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, Attachment, or Appendix means such Article or Section of this Agreement or such Attachment or Appendix to

this Agreement, or such Section of the SGIP or such Attachment or Appendix to the SGIP, 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 Section; (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".

- 11.6 Governing Law, Regulatory Authority, and Rules. The validity, interpretation and enforcement of this Agreement 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. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.
- 11.7 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.
- 11.8 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 either 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. Termination or default of this 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 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.

- 11.9 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.
- 11.10 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.
- 11.11 Amendment. The Parties may by mutual agreement amend this Agreement by a written instrument duly executed by both of the Parties.
- 11.12 Modification by the Parties. The Parties may by mutual agreement amend the Appendices to this Agreement by a written instrument duly executed by both of the Parties. Such amendment shall become effective and a part of this Agreement upon satisfaction of all applicable laws and regulations.
- 11.13 Reservation of Rights. The ISO shall have the right to make a unilateral filing with FERC to modify this 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 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 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.

- 11.14 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.
- 11.15 Assignment. This Agreement may be assigned by a Party only with the written consent of the other Party; provided that a Party may assign this 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 Agreement; and provided further that the Interconnection Customer shall have the right to assign this Agreement, without the consent of the other Party, for collateral security purposes to aid in providing financing for the 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 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.
- 11.16 Severability. If any provisions or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.
- 11.17 Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties 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 Transmission Provider Participating TO or the ISO be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

California Independent System Operator Corporation

Signed _____

Name (Printed): _____

Title _____

[Insert name of Interconnection Customer]

Signed _____

Name (Printed): _____

Title _____

**Attachment A to
Facilities Study Agreement**

**Data to Be Provided by the Interconnection Customer
with the Facilities Study Agreement**

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

On the one-line diagram, indicate the generation capacity attached at each metering location.
(Maximum load on CT/PT)

On the one-line diagram, indicate the location of auxiliary power. (Minimum load on CT/PT)
Amps

One set of metering is required for each generation connection to the new ring bus or existing Participating TO station. Number of generation connections: _____

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 the one-line diagram).

What type of control system or PLC will be located at the Small Generating Facility?

What protocol does the control system or PLC use?

Please provide a 7.5-minute quadrangle map of the site. Indicate the plant, station, transmission line, and property lines.

Physical dimensions of the proposed interconnection station:

Bus length from generation to interconnection station:

Line length from interconnection station to ISO Controlled Grid.

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 Participating TO.

Is the Small Generating Facility located in Participating TO's service area?

Yes _____ No _____ If No, please provide name of local provider:

Please provide the following proposed schedule dates:

Begin Construction Date: _____

Generator step-up transformers receive back feed power Date: _____

Generation Testing Date: _____

Commercial Operation Date: _____

Attachment 9

INTERCONNECTION PROCEDURES FOR A WIND GENERATING PLANT

Attachment 9 sets forth procedures specific to a wind generating plant. All other requirements of this SGIP 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 2.3 of this SGIP, 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 SGIP.

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.

ISO TARIFF APPENDIX BB

Prior to the date that the CAISO Tariff as filed in FERC Docket No. ER06-615 shall become effective, the CAISO will continue to operate as provided in the ISO Tariff in effect prior to such time. For purposes of activity related to the preparation for allocation, auction and transfer of Congestion Revenue Rights, the CAISO shall operate pursuant to this Appendix BB. This Appendix BB is included in the CAISO Tariff to set forth temporary provisions that are derived from conditionally accepted the CAISO Tariff in FERC Docket ER06-615 that enable the CAISO to implement certain activities in preparation of its first annual and monthly CRR Allocation and CRR Auction. These provisions enable the CAISO to: 1) register and qualify entities that intend to participate in the CRR Allocation, CRR Auction, or to transfer and obtain allocated or awarded CRRs through the Secondary Registration System; 2) provide to Market Participants any relevant information to enable such parties to participate in the CRR Allocation, CRR Auction or the Secondary Registration System; 3) obtain from Candidate CRR Holders eligible to participate in the CRR Allocation information necessary to verify the load metric that is eligible for allocation of CRRs; and 4) obtain from Participating TOs, entities that have TORs, and New Participating TOs the Transmission Rights and Transmission Curtailment Instructions that will be used to validate ETC, TOR and Converted Rights Self-Schedules submitted consistent with such rights as well as to model usage under such rights in the allocation and auction of CRRs.

This Appendix BB, therefore, does not replace or supersede the provisions contained in the ISO Tariff in effect prior to the effective date of the version of the tariff as filed and accepted in FERC Docket ER06-615, which will continue to apply until such time that the tariff provisions as filed and finally approved in Docket ER06-615 become fully effective. When all the provisions as filed and conditionally accepted in Docket ER06-615 become fully effective the CAISO will conform its tariff accordingly.

PART A. INFORMATION TO BE PROVIDED BY THE CAISO TO MARKET PARTICIPANTS.

The provisions of this Part A are necessary to enable the CAISO to provide information to Market Participants, Candidate CRR Holders, and CRR Holders that will enable entities to prepare for participation in the CRR Allocation and CRR Auction to be conducted in the summer and fall of 2007.

6.5.1 Communication With Market Participants, Congestion Revenue Rights Participants, and the Public.

6.5.1.1 Market Participants With Non-Disclosure Agreements.

6.5.1.1.1 Annually, the CAISO shall provide information that will include, but is not limited to, the following:

- (a) CRR Full Network Model;
- (b) Constraints and interface definitions;
- (c) Load Distribution Factors for each CRR Allocation and CRR Auction that are published prior to the CRR Allocation and CRR Auction; and
- (d) Nominations and/or parameters to be used for modeling in each annual CRR Allocation and CRR Auction processes: Transmission Ownership Rights, Existing Contracts and Converted Rights expected usage, and Merchant Transmission CRRs.

6.5.1.1.2 Monthly, the CAISO shall provide information that will include, but is not limited to, the following:

- (a) CRR Full Network Model;
- (b) Constraints and interface definitions;
- (c) Load Distribution Factors for each CRR Allocation and CRR Auction that is published prior to the CRR Allocation and CRR Auction; and
- (d) Nominations and/or parameters to be used for modeling in each monthly CRR Allocation and CRR Auction processes: Transmission Ownership Rights, Existing Contracts and Converted Rights expected usage, and Merchant Transmission CRRs.

6.5.1.2 CRR Participants Without Non-Disclosure Agreements.

6.5.1.2.1 Annually, the CAISO shall provide CRR information specific to that CRR Holder or Candidate CRR Holder as it relates to participation in the annual CRR Allocation or CRR Auction.

6.5.1.2.2 Monthly, the CAISO shall provide CRR information specific to that CRR Holder or Candidate CRR Holder as it relates to participation in the monthly CRR Allocation or CRR Auction.

6.5.1.3 Public Market Information.

6.5.1.3.1 Annually, the CAISO shall publish the following information including, but not limited to:

- (a) Market Clearing Prices for all Aggregated PNodes used in the CRR Auction clearing for on-peak and off-peak;
- (b) CRR Holdings by CRR Holder (including):
 - (i) CRR Source name(s);
 - (ii) CRR Sink name(s);
 - (iii) CRR quantity (MW) for each CRR Source(s) and CRR Sink(s);
 - (iv) CRR start and end dates;
 - (v) Time of use specifications for the CRR(s); and
 - (vi) Whether the CRR is a CRR Option or CRR Obligation.

6.5.1.3.2 Monthly, the CAISO shall publish the following information including, but not limited to:

- (a) Market Clearing Prices for all Aggregated PNodes used in the CRR Auction clearing for on-peak and off-peak;
- (b) CRR Holdings by CRR Holder (including):
 - (i) CRR Source name(s);
 - (ii) CRR Sink name(s);
 - (iii) CRR quantity (MW) for each CRR Source(s) and CRR Sink(s);
 - (iv) CRR start and end dates;
 - (v) Time of use specifications for the CRR(s); and
 - (vi) Whether the CRR is a CRR Option or a CRR Obligation.

6.5.1.3.3 Seasonally, the CAISO shall publish the following information including, but not limited to:

- (a) Set of LDFs that represent typical seasonal on-peak and off-peak values, not used for Settlements, before the new season.

PART B. TRANSMISSION RIGHTS AND TRANSMISSION CURTAILMENT (TRTC)

INSTRUCTIONS

The provisions of this Part B are necessary to enable the CAISO to collect and implement the Transmission Rights and Transmission Curtailment Instructions that will be used to model ETCs, TORs, and Converted Rights in the CRR Allocation and CRR Auction to be conducted in the summer and fall of 2007.

4.3.1.2.1 New Participating TOs shall complete TRTC Instructions for their Converted Rights as provided in Section 16.4.5 of this Appendix. To the extent such Converted Rights derive from ETCs with Original Participating TOs, the New Participating TOs and the appropriate Original Participating TO shall develop the TRTC Instructions together.

16.4 Transmission Rights and Transmission Curtailment Instructions

16.4.1 Responsibility to Create TRTC Instructions

Each Participating TO and Existing Rights holder will work with the CAISO to develop the Transmission Rights and Transmission Curtailment (“TRTC”) Instructions that allow Existing Contracts to be exercised in a way that: (i) maintains the existing scheduling and curtailment priorities under the Existing Contract; (ii) is minimally burdensome to the CAISO (i.e., creates the least impact on the CAISO’s preferred operational policies and procedures); (iii) to the extent possible, imposes no additional financial burden on either the Participating TO or the holder of Existing Rights (beyond that in the Existing Contract); (iv) consistent with the terms of the Existing Contracts, makes as much transmission capacity not otherwise utilized by the holder of Existing Rights available as possible to the CAISO for allocation to Market Participants; (v) is minimally burdensome to the Participating TO and the Existing Rights holder from an operational point of view; and (vi) does not require the CAISO to interpret or underwrite the economics of the Existing Contract. The parties to Existing Contracts will attempt to jointly develop and agree on any TRTC Instructions that will be submitted to the CAISO. The parties to an Existing Contract shall also be responsible to submit to the CAISO any other necessary operating instructions based on their contract interpretations needed by the CAISO to enable the CAISO to perform its duties.

16.4.2 Responsible PTO for Multiple Participating TO Parties to an Existing Contract.

To the extent there is more than one Participating TO providing transmission service under an Existing Contract or there is a set of Existing Contracts which are interdependent from the point of view of submitting instructions to the CAISO involving more than one Participating TO, the relevant Participating TOs will designate a single Participating TO as the responsible PTO and will notify the CAISO accordingly. If no such responsible PTO is designated by the relevant Participating TOs or the CAISO is not notified of such designation, the CAISO shall designate one of them as the responsible PTO and notify the relevant Participating TOs accordingly. The responsible PTO designated pursuant to this section shall have the same responsibility as the Participating TO under this Section 16.4.

16.4.3 Scheduling Coordinator Responsibilities

The Scheduling Coordinator designated by the parties to an Existing Contract as the responsible entity for submitting ETC Self-Schedules for the relevant Existing Contract shall submit ETC Self-Schedules consistent with the terms and conditions specified in the TRTC Instructions.

16.4.4 Submission of TRTC Instructions.

For each Existing Contract, the Participating TO providing transmission service under the Existing Contract (or the responsible PTO identified in Section 16.4.2) shall be obligated to submit the TRTC Instructions to the CAISO electronically on behalf of the holders of Existing Rights, unless the parties to the Existing Contract agree otherwise. The Participating TO shall notify the CAISO in writing the identity of the responsible party for submission of the TRTC Instructions as decided by the parties to the Existing Contract and the term of such agreement between the parties to the Existing Contract. The Participating TO shall undertake all obligations with respect to the submission of the TRTC Instructions to the CAISO and any subsequent obligations that follow with respect to the creation, management and updates to the TRTC Instructions. The CAISO is responsible for implementing only one set of TRTC Instructions for each Existing Contract and only those TRTC Instructions that have been received and accepted by the CAISO. The Participating TO shall submit the TRTC Instructions to the CAISO associated with Existing Contracts or sets of interdependent Existing Contracts thirty (30) days prior to the date on which the scheduling or curtailment of the use of the Existing Rights is to change or commence.

16.4.5 TRTC Instructions Content.

TRTC Instructions will include the following information at a minimum and such other information as the CAISO may reasonably require the Participating TO to provide to enable the CAISO to carry out its functions under the CAISO Tariff, Operating Procedures and Business Practice Manuals:

- (1) A unique Contract Reference Number for each source and sink combination applicable to the Existing Contract (i.e., the CRN that will be assigned by the CAISO and

- communicated to the Participating TO that references a single Existing Contract or a set of interdependent Existing Contracts for each source and sink combination);
- (2) Whether the instruction can be exercised independent of the CAISO's day-to-day involvement ("Yes/No");
 - (3) Name of an operational single point of contact for instructions and a 24-hour a day telephone number for the Participating TO contact for Existing Contract issues or the agreed upon party;
 - (4) Name(s) and number(s) of Existing Contract(s) that are represented by the unique CRN;
 - (5) The following information as stored in the Master File: (a) the applicable Point(s) of Receipt and Point(s) of Delivery; (b) for each Point of Receipt, the resource names for the physical resources as the eligible sources (eligible physical sources include Generating Units and System Resources), and for each Point of Delivery the resource names for the physical resources as the eligible sinks (eligible physical sinks include Load PNodes, custom Load Aggregation Points and System Resources); (c) for each physical source or sink the maximum Existing Rights capacity (MW) that can be scheduled as an Existing Right under the Existing Contract; and (d) for each physical source and sink the Scheduling Coordinator(s) and their Business Associate Identification ("BAID") that is(are) eligible to submit ETC Self-Schedules utilizing these sources and sinks;
 - (6) Names of the party(ies) to the Existing Contract(s);
 - (7) The Scheduling Coordinator BAID that is entitled to the Settlement of reversal of Congestion Charges;
 - (8) Type(s) of service rights by the holder of the Existing Rights, by type of service (firm, conditional firm, or non-firm), with priorities for firm and conditional firm transmission services and maximum amounts of service right in MW;

- (9) Instructions for the allowable timeframes at which the ETC Self-Schedules and ETC Self-Schedule changes may be submitted to the CAISO, which include whether the Scheduling Coordinator may submit ETC Self-Schedules or ETC Self-Schedule changes: (a) into the DAM; (b) into the HASP and the RTM; (c) after the close of the bidding into the HASP and the RTM, but before T-20 minutes for that Trading Hour of Trading Day; and (d) at or after T-20 minutes and into the Trading Hour of Trading Day; in addition, the TRTC Instructions may also include any additional comments and restrictions on the submission time of ETC Self-Schedules and ETC Self-Schedule changes;
- (10) Term or service period(s) of the Existing Contract(s);
- (11) Any special procedures that would require the CAISO to implement curtailments in any manner different from pro rata reduction of the transfer capability of the transmission line; any such TRTC Instructions submitted to the CAISO must be clear, unambiguous, and not require the CAISO to make any judgments or interpretations as to the meaning intent, results, or purpose of the curtailment procedures or the Existing Contract and the section of the Existing Contract that provides this right for reference, otherwise, they will not be accepted by the CAISO;
- (12) The forecasted usage patterns for each Existing Contract for the upcoming annual period of the annual CRR release processes as well as for the upcoming monthly period of the monthly CRR release processes, which will consist of hourly MWh data over the whole year for those resources that will use the Existing Contract; this information will be considered by the CAISO in managing its accounting for usage of Existing Rights in the release of CRRs; this information shall not be used by the CAISO to validate ETC Self-Schedules when submitted by Scheduling Coordinators and therefore shall not affect the Existing Rights holder's ability to utilize its rights under the Existing Contract;

- (13) Whether or not the Existing Contract provides for the right to self-provide Ancillary Services; and
- (14) Specification of any contract requirements in the ETC that warrants special consideration in the implementation of the physical rights under the ETC.

16.4.6 Changes and Updates to TRTC Instructions.

Updates or changes to the TRTC Instructions must be submitted to the CAISO through a revised set of TRTC Instructions by the Participating TO, on an as needed or as required basis determined by the parties to the Existing Contracts. The CAISO will implement the updated or changed TRTC Instructions as soon as practicable but no later than seven (7) days after receiving clear and unambiguous details of the updated or changed instructions under normal conditions. If the CAISO finds the TRTC Instructions to be inconsistent with the CAISO Tariff, the CAISO will notify the Participating TO within forty-eight (48) hours after receipt of the updated or changed TRTC Instructions indicating the nature of the problem and allowing the Participating TO to resubmit the TRTC Instructions as if they were new, updated or changed TRTC Instructions. If the CAISO finds the updated or changed TRTC Instructions to be acceptable, the CAISO will time-stamp the updated TRTC Instructions as received, confirm such receipt to the Participating TO, and indicate the time at which the updated TRTC Instructions take effect if prior to the seven (7) day deadline referred to above. In the event of a System Emergency, the CAISO will implement such submitted changes to the TRTC Instructions as soon as practical.

16.4.7 Treatment of TRTC Instructions.

16.4.7.1 TRTC Instructions Can Be Exercised Independently.

To the extent that the TRTC Instructions can be exercised independently of the CAISO by the parties to the Existing Contract and the results forwarded to the CAISO, the TRTC Instructions shall be exercised by the Participating TOs, and the outcomes shall be forwarded to the CAISO. The determination of whether the TRTC Instructions can be “exercised independently of the CAISO by the parties to the Existing Contract” shall be made using the same procedures described in Section 16.4.8 of this Appendix.

16.4.7.2 TRTC Instructions Cannot Be Exercised Independently.

To the extent that the TRTC Instructions cannot be exercised independently of the CAISO and the results forwarded to the CAISO (because, for example, they require iteration with the CAISO’s Bid submission and scheduling process, would unduly interfere with the CAISO’s management of the Real-Time Market, including curtailments, or would unduly interfere with the ability of the holder of rights to exercise its rights), the TRTC Instructions will be provided to the CAISO for day-to-day implementation. The TRTC Instructions will be provided by the Participating TO to the CAISO for implementation unless the parties to the Existing Contracts otherwise agree that the holder of the Existing Rights will do so. For these TRTC Instructions, the Scheduling Coordinators representing the holders of Existing Rights will submit their Bids to the CAISO for implementation in accordance with the TRTC Instructions. In this case, the CAISO shall act as the scheduling agent for the Participating TO with regard to Existing Rights.

16.4.8 CAISO Role in Existing Contracts.

The CAISO will have no role in interpreting Existing Contracts. The parties to an Existing Contract will, in the first instance, attempt jointly to agree on any TRTC Instructions that will be submitted to the CAISO. In the event that the parties to the Existing Contract cannot agree upon the TRTC Instructions submitted by the parties to the Existing Contract, the dispute resolution provisions of the Existing Contract, if applicable, shall be used to resolve the dispute; provided that, until the dispute is resolved, and unless the Existing Contract specifies otherwise, the CAISO shall implement the Participating TO's TRTC Instructions. If both parties to an Existing Contract are Participating TOs and the parties cannot agree to the TRTC Instructions submitted by the parties, until the dispute is resolved, and unless the Existing Contract specifies otherwise, the CAISO shall implement the TRTC Instructions of the first Participating TO for which the Existing Contract is an Encumbrance. The CAISO shall not be responsible for resolution of any disputes that arise over the accuracy of the TRTC Instructions consistent with its obligations in Section 16.4.5 of this Appendix.

16.4.9 Implementation of TRTC Instructions.

The CAISO shall determine, based on the information provided by the Participating TOs under TRTC Instructions, the transmission capacities that (i) must be reserved for firm Existing Rights at Scheduling Points, (ii) may be allocated for use as CAISO transmission service (i.e., new firm uses), (iii) must be reserved by the CAISO for conditional firm Existing Rights, and (iv) remain for any non-firm Existing Rights for which a Participating TO has no discretion over whether or not to provide such non-firm service.

The CAISO shall coordinate the scheduling of Existing Rights with the scheduling of CAISO transmission service, using the CAISO's Bid submission rules. In doing so, the CAISO shall create an automated day-to-day verification process based on parameters provided by the Participating TO for the Existing Contract to serve as the basis for ETC Self-Schedule validation. The Participating TO will be responsible for: (1) the accuracy of the data files against which the CAISO will validate the ETC Self-Schedule; and (2) providing the data file to the holder of Existing Rights as well as the CAISO.

The CAISO shall recognize that the obligations, terms or conditions of Existing Contracts may not be changed without the voluntary consent of all parties to the contract (unless such contract may be changed pursuant to any applicable dispute resolution provisions in the contract or pursuant to Section 205 or Section 206 of the FPA and the FERC's Rules and Regulations or as otherwise provided by law).

The parties to Existing Contracts shall remain liable for their performance under the Existing Contracts.

The CAISO shall be liable in accordance with the provisions of this CAISO Tariff for any damage or injury caused by its non-compliance with the TRTC Instructions submitted to it pursuant to this Section 16.4.

Unless specified otherwise, in the event that the dispute resolution mechanisms prescribed in an Existing Contract, including all recourses legally available under the contract, cannot, in the first instance, result in a resolution of such a dispute, the ISO ADR Procedures will be used to resolve any disputes between the CAISO and the Participating TO regarding any aspects of the implementation of this Section 16.4, including the reasonableness of a Participating TO's TRTC Instructions or any other decision rules which the Participating TO may submit to the CAISO as part of the TRTC Instructions. The holders of Existing Rights under the Existing Contract shall have standing to participate in the ISO ADR Procedures.

17.1 Transmission Rights and Transmission Curtailment Instructions

17.1.1 Responsibility to Create TRTC Instructions

To enable the CAISO to exercise its responsibilities as Control Area Operator in accordance with Applicable Reliability Criteria, each Non-Participating TO holding a TOR must work with the CAISO to develop the TRTC Instructions that allow the TOR to be accommodated in a way that: (i) maintains the existing scheduling and curtailment priorities of the TOR holder; (ii) is minimally burdensome to the CAISO (i.e., creates the least impact on the CAISO's preferred operational policies and procedures); (iii) to the extent possible, imposes no additional financial burden on the TOR holder (beyond that set forth in an applicable Existing Contract or any other contract pertaining to the TOR); (iv) is minimally burdensome to the TOR holder from an operational point of view; and (v) does not require the CAISO to interpret or underwrite the economics of any applicable Existing Contract. To enable the CAISO to exercise its responsibilities as Control Area Operator in accordance with Applicable Reliability Criteria, the parties holding joint ownership interests and Entitlements in facilities including TORs must attempt to jointly develop and agree on any TRTC Instructions that will be submitted to the CAISO. TOR holders and any other parties holding joint ownership interests and Entitlements in facilities including TORs shall also be responsible to submit to the CAISO any other necessary operating instructions based on their interpretations of the agreements applicable to those TORs and joint ownership interests and Entitlements needed by the CAISO to enable the CAISO to perform its duties.

17.1.2 TOR Scheduling Coordinator Responsibilities

To enable the CAISO to exercise its responsibilities as Control Area Operator in accordance with Applicable Reliability Criteria, each TOR holder must designate a Scheduling Coordinator as the responsible entity for submitting TOR Self-Schedules for the relevant TOR. The designated Scheduling Coordinator shall submit TOR Self-Schedules consistent with the terms and conditions specified in the TRTC Instructions.

17.1.3 Submission of TRTC Instructions.

For each TOR, the Non-Participating TO holding the TOR shall be obligated to submit TRTC Instructions to the CAISO electronically, unless the Non-Participating TO specifies to the CAISO otherwise. The Non-Participating TO shall notify the CAISO in writing the identity of the responsible party for submission of the TRTC Instructions, subject to the terms of any applicable Existing Contract that may specify the responsible party for submission of the TRTC Instructions and the term of such agreement between the parties to the Existing Contract. The Non-Participating TO shall undertake all obligations with respect to the submission of the TRTC Instructions to the CAISO and any subsequent obligations that follow with respect to the creation, management and updates to the TRTC Instructions. The CAISO is responsible for implementing only one set of TRTC Instructions for each TOR and for implementing only those TRTC Instructions that have been received and accepted by the CAISO. The Non-Participating TO shall submit the TRTC Instructions to the CAISO associated with its TORs thirty (30) days prior to the date on which the scheduling or curtailment of the use of the TORs is to change or commence.

17.1.4 TRTC Instructions Content.

TRTC Instructions will include the following information at a minimum and such other information as the CAISO may reasonably require the Non-Participating TO holder of a TOR to provide to enable the CAISO to carry out its functions under the CAISO Tariff, Operating Procedures and Business Practice Manuals:

- (1) A unique Contract Reference Number for each source and sink combination applicable to the TOR (TOR reference number or CRN that will be assigned by the CAISO and communicated to the Non-Participating TO that references a single TOR or a set of interdependent TORs for each source and sink combination);
- (2) Whether the instruction can be exercised independent of the CAISO's day-to-day involvement ("Yes/No");

- (3) Name of an operational single point of contact for instructions and a 24-hour a day telephone number for the Non-Participating TO contact for TOR issues or the agreed upon party;
- (4) Name(s) and number(s) of TOR(s) that are represented by the unique CRN;
- (5) The following information, as stored in the Master File: (a) the applicable Point(s) of Receipt and Point(s) of Delivery; (b) for each Point of Receipt, the resource names for the physical resources as the eligible sources (eligible physical sources include Generating Units and System Resources), and for each Point of Delivery the resource names for the physical resources as the eligible sinks (eligible physical sinks include Load PNodes, Custom Load Aggregation Points and System Resources); (c) for each physical source or sink the maximum capacity (MW) that can be scheduled as a TOR under the Existing Contract; and (d) for each physical source and sink the Scheduling Coordinator(s) and their Business Associate Identification ("BAID") that is(are) eligible to submit TOR Self-Schedules utilizing these sources and sinks;
- (6) Names of the party(ies) holding the TOR(s) and the parties to any agreements applicable to the TORs;
- (7) The Scheduling Coordinator BAID that is entitled to the Settlement of reversal of Congestion Charges;
- (8) Amount of TORs, in maximum MW, that may be utilized under the relevant TRTC Instructions;
- (9) Instructions for the allowable timeframes at which the TOR Self-Schedules and TOR Self-Schedule changes may be submitted to the CAISO, which include whether the Scheduling Coordinator may submit TOR Self-Schedules or TOR Self-Schedule changes: (a) into the DAM; (b) into the HASP and the RTM; (c) after the close of the bidding into the HASP and the RTM, but before T-20 minutes for that Trading Hour of

Trading Day; and (d) at or after T-20 minutes and into the Trading Hour of Trading Day; in addition, the Non-Participating TO may also provide any additional comments and restrictions on the submission time of TOR Self-Schedules and TOR Self-Schedule changes;

- (10) Term of ownership interest in the TOR(s) and of any agreements applicable to the TOR(s);
- (11) Any special procedures that would require the CAISO to implement curtailments in any manner different than pro rata reduction of the transfer capability of the transmission line; any such instructions submitted to the CAISO must be clear, unambiguous, and not require the CAISO to make any judgments or interpretations as to the meaning intent, results, or purpose of the curtailment procedures or of any applicable Existing Contract, otherwise, they will not be accepted by the CAISO; and
- (12) Whether or not the TOR provides the right to self-provide Ancillary Services.

17.1.5 Changes and Updates to TRTC Instructions.

Updates or changes to the TRTC Instructions must be submitted to the CAISO through a revised set of TRTC Instructions by the Non-Participating TO, on an as needed or as required basis. The CAISO will implement the updated or changed TRTC Instructions as soon as practicable but no later than seven (7) days after receiving clear and unambiguous details of the updated or changed instructions under normal conditions. If the CAISO finds the TRTC Instructions to be inconsistent with the CAISO Tariff, the CAISO will notify the Non-Participating TO within forty-eight (48) hours after receipt of the updated or changed TRTC Instructions indicating the nature of the problem and allowing the Non-Participating TO to resubmit

the TRTC Instructions as if they were new, updated or changed TRTC Instructions. If the CAISO finds the updated or changed TRTC Instructions to be acceptable, the CAISO will time-stamp the updated TRTC Instructions as received, confirm such receipt to the Non-Participating TO, and indicate the time at which the updated instructions take effect if prior to the seven (7) day deadline referred to above. In the event of a System Emergency, the CAISO will implement such submitted changes to the TRTC Instructions as soon as practical.

17.1.6 CAISO Role in Accepting TRTC Instructions.

The parties holding joint ownership interests and Entitlements in a facility including a TOR must, in the first instance, attempt jointly to agree on any TRTC Instructions that will be submitted to the CAISO. In the event that the parties holding joint ownership interests and Entitlements in a facility including a TOR cannot agree upon the TRTC Instructions, the dispute resolution provisions of any applicable Existing Contract shall be used to resolve the dispute; provided that, until the dispute is resolved, and unless the applicable Existing Contract specifies otherwise, the CAISO shall implement the Participating TO's TRTC Instructions, if one of the parties holding a joint ownership interest or an Entitlement in the facility is a Participating TO. If no party holding a joint ownership interest or Entitlement in a facility including a TOR is a Participating TO and the parties cannot agree to the TRTC Instructions to be submitted by the parties, until the dispute is resolved, the CAISO shall implement the TRTC Instructions of the Non-Participating TO with the greatest ownership interest in the TOR. The CAISO shall not be responsible for resolution of any disputes that arise over the accuracy of the TRTC Instructions consistent with its obligations in Section 17.1.4 of this Appendix.

17.1.7 Implementation of TRTC Instructions.

The CAISO shall determine, based on the information provided by the Non-Participating TOs under TRTC Instructions, the transmission capacities that must be reserved for TORs at Scheduling Points.

The CAISO shall coordinate the scheduling of TORs with the scheduling of CAISO transmission service, using the CAISO's Bid submission rules. In doing so, the CAISO shall create an automated day-to-day verification process based on parameters provided by the Non-Participating TO for the TOR to serve as the basis for TOR Self-Schedule validation. The Non-Participating TO will be responsible for: (1) the accuracy of the data files against which the CAISO will validate the TOR Self-Schedule; and (2) providing the data file to the CAISO.

The TOR holders shall remain liable for their performance under any applicable Existing Contracts or other agreements pertaining to their TORs. The CAISO shall be liable in accordance with the provisions of this CAISO Tariff for any damage or injury caused by its non-compliance with the TRTC Instructions submitted to it pursuant to this Section 17.1.

Unless specified otherwise, in the event that the dispute resolution mechanisms prescribed in an Existing Contract applicable to a TOR, including all recourses legally available under the contract, cannot, in the first instance, result in a resolution of such a dispute, the ISO ADR Procedures will be used to resolve any disputes between the CAISO and the Non-Participating TO regarding any aspects of the implementation of this Section 17.1, including the reasonableness of a Non-Participating TO's TRTC Instructions or any other decision rules which the Non-Participating TO may submit to the CAISO as part of the TRTC Instructions. The holders of TORs shall have standing to participate in the ISO ADR Procedures.

PART C. MSS OPERATOR SETTLEMENT OPTIONS

In preparation for the first annual CRR Allocation to be held in 2007 prior to the date on which the version of the CAISO Tariff as filed and accepted in FERC Docket No. ER06-615 shall become effective, an MSS Operator Candidate CRR Holder's load eligibility for allocation of CRRs in the annual and monthly CRR Allocation will depend on its election of Settlement options as follows.

[NOT USED]

[NOT USED]

[NOT USED]

4.9.13.1 Gross or Net Settlement.

An MSS Operator has the option to settle with the CAISO on either a gross basis or a net basis for its Load and generating resources. This election shall be made annually for a period consistent with annual CRR Allocation. If the MSS Operator elects net settlement, then CRRs would be allocated on MSS net Load and the MSS may choose the MSS LAP as its CRR Sink in the first tiers of CRR Allocation. If the MSS Operator elects gross settlement, then CRRs would be allocated on a gross load basis and the MSS may not choose the MSS LAPs as its CRR Sink in the first tiers of CRR Allocation.

PART D. CANDIDATE CRR HOLDER AND CRR HOLDER REQUIREMENTS

The provisions of this Part D are necessary to enable the CAISO to register and certify Candidate CRR Holders in advance of their participation in the CRR Allocation and CRR Auction to be conducted in the summer and fall of 2007.

4.10 Candidate CRR Holder and CRR Holder Registration.

Only entities that are registered and qualified as a Candidate CRR Holder or CRR Holder shall: 1) submit nominations to CRR Allocations; 2) submit bids to CRR Auctions; and 3) register as a CRR Holder through the Secondary Registration System. In order to be registered and qualified as Candidate CRR Holders or CRR Holders, entities must have met the all of the requirements specified in this Section 4.10.

4.10.1 Procedure to Become a Candidate CRR Holder.

4.10.1.1 Candidate CRR Holder Application.

To become a Candidate CRR Holder, a Candidate CRR Holder applicant must submit a completed written application, as provided in the applicable form posted on the CAISO Website, to the CAISO by mail, or in person. A Candidate CRR Holder applicant may retrieve the application and necessary information from the CAISO Website.

4.10.1.2 CAISO Information.

The CAISO will provide the following information, in its most current form, on the CAISO Website and, upon request by a Candidate CRR Holder applicant, the CAISO will send the requested information by electronic mail:

- (a) the Candidate CRR Holder application form;
- (b) the CAISO Tariff and Business Practice Manuals; and
- (c) an application for an Unsecured Credit Limit for Candidate CRR Holder applicants requesting an Unsecured Credit Limit in lieu of another form of Financial Security.

4.10.1.3 Candidate CRR Holder Applicant Submits Application.

At least 60 days before the proposed commencement of the CRR Allocation or CRR Auction, or the effective date of the CRR transfer through the Secondary Registration System, in which a Candidate CRR Holder desires to participate as applicable, the Candidate CRR Holder applicant must return a completed application form with the non-refundable application fee set by the CAISO Governing Board to cover the application processing costs and the costs of furnishing the CAISO Tariff and other documents.

4.10.1.4 Notice of Receipt.

Within three (3) Business Days of receiving the application, the CAISO will send a written notification to the Candidate CRR Holder applicant that it has received the application and the non-refundable fee.

4.10.1.5 CAISO Review of Application.

Within ten (10) Business Days after receiving an application, the CAISO will notify the Candidate CRR Holder applicant whether the Candidate CRR Holder applicant has fulfilled all necessary information as set forth in Section 4.10.1 of this Appendix. If the Candidate CRR Holder applicant fails to fulfill all application requirements within a year from the date that the CAISO acknowledges receipt of the Candidate CRR Holder application, the application will be nullified and the applicant will be required to resubmit a new application in order to reinstate its status as a Candidate CRR Holder applicant.

4.10.1.5.1 Information Requirements.

The Candidate CRR Holder applicant must submit with its application:

- (a) the proposed date for commencement of the CRR Allocation, CRR Auction or Secondary Registration System in which the applicant intends to qualify to participate, which may not be less than sixty (60) days after the date the application was filed, unless waived by the CAISO;

- (b) Financial Security information as set forth in Sections 12.1 and 12.6 of the ISO Tariff;
- (c) proof of completion of CRR training or expected completion of CRR training; and
- (d) the prescribed non-refundable application fee.

4.10.1.5.2 Candidate CRR Holder Load Serving Entity Certifications.

A Candidate CRR Holder applicant that intends to obtain CRRs through the CRR Allocation process must certify that it qualifies as a Load Serving Entity as defined in the CAISO Tariff. A Candidate CRR Holder applicant that intends to participate in the CRR Allocation for load it serves located outside the CAISO Control Area must certify that it qualifies as that load's load serving entity and prior to actual participation in the CRR Allocation will also be required to fulfill the requirements in Section 36.9 of this Appendix.

4.10.1.6 Deficient Application.

In the event that the CAISO has determined that the Candidate CRR Holder application as submitted is deficient the CAISO will send a written notification of the deficiency to the Candidate CRR Holder applicant within ten (10) Business Days of receipt by the CAISO of the application explaining the deficiency and requesting additional information.

4.10.1.6.1 Candidate CRR Holder Applicant's Additional Information.

Once the CAISO requests additional information, the Candidate CRR Holder applicant has five (5) Business Days, or such longer period as the CAISO may agree, to provide the additional material requested by the CAISO.

4.10.1.6.2 No Response from Candidate CRR Holder Applicant.

If the Candidate CRR Holder applicant does not submit additional information within five (5) Business Days or the longer period referred to in Section 4.10.1.6.1 of this Appendix, the application may be rejected by the CAISO.

4.10.1.7 CAISO Acceptance or Rejection of an Application.

4.10.1.7.1 Acceptance or Rejection Notification.

- (a) If the CAISO accepts the application, it will send a written notification to the Candidate CRR Holder applicant stating that its application has been accepted.
- (b) If the CAISO rejects the application, the CAISO will send a rejection letter stating one or more of the following grounds:
 - i. incomplete information;
 - ii. non-compliance with Financial Security requirements; or
 - iii. non-compliance with any other CAISO Tariff requirements.

Upon request, the CAISO will provide guidance as to how the Candidate CRR Holder applicant can cure the grounds for the rejection.

4.10.1.7.2 Time for Processing Application.

The CAISO will make a decision whether to accept or reject the application within ten (10) Business Days of receipt of the application. If more information is requested, the CAISO will make a final decision within ten (10) Business Days of the receipt of all outstanding or additional information requested.

4.10.1.8 Candidate CRR Holder Applicant's Response.

4.10.1.8.1 Candidate CRR Holder Applicant's Acceptance.

If the CAISO accepts the application, the Candidate CRR Holder applicant must return an executed CRR Entity Agreement and any required letter of credit, guaranty, escrow agreement or other form of Financial Security for the CAISO Security Amount, as applicable.

4.10.1.8.2 Candidate CRR Holder Applicant's Rejection.

4.10.1.8.2.1 Resubmittal.

If a Candidate CRR Holder's application is rejected, the Candidate CRR Holder applicant may resubmit its application at any time. An additional application fee will not be required for the second application submitted within six (6) months after the CAISO's issuance of a rejection.

4.10.1.8.2.2 Appeal.

The Candidate CRR Holder applicant may also appeal against the rejection of an application by the CAISO. An appeal must be submitted within twenty (20) Business Days following the CAISO's issuance of a rejection of its application.

4.10.1.9 Final Registration and Qualification of Candidate CRR Holder Applicant.

4.10.1.9.1 Notice of Completed Registration and Qualification of Candidate CRR Holder.

Once the CAISO has accepted a Candidate CRR Holder applicant's application, the CAISO will provide the Candidate CRR Holder applicant with a final written notice to certify that a Candidate CRR Holder applicant has become a Candidate CRR Holder. The CAISO shall issue such final written notice of full registration and qualification as a Candidate CRR Holder after the CAISO has determined that the Candidate CRR Holder applicant has fully satisfied all the following requirements:

- (a) fully executed a CRR Entity Agreement with the CAISO;
- (b) provided its bank account information and arranged for Fed-Wire transfers;
- (c) met the Financial Security requirements of Sections 12.1 and 12.6 of the ISO Tariff;
- (d) certified that it has attended required CRR training; and
- (e) obtained and installed any necessary software for communication with the CAISO as necessary.

4.10.1.9.2 Market Notice

The CAISO shall issue a Market Notice stating the new Candidate CRR Holder status.

4.10.2 Candidate CRR Holder's and CRR Holder's Ongoing Obligations After Registration and Qualification.

4.10.2.1 Candidate CRR Holder and CRR Holder Obligation to Report Changes.

4.10.2.1.1 Obligation to Report a Change in Filed Information.

Each Candidate CRR Holder and CRR Holder has an ongoing obligation to inform the CAISO of any changes to any of the information submitted by it to the CAISO as part of its application to become a Candidate CRR Holder, including any changes to the additional information requested by the CAISO. The applicable Business Practice Manual sets forth the procedures for changing the Candidate CRR Holder or CRR Holder information and timing of notifying the CAISO of such changes.

4.10.2.1.2 Obligation to Report a Material Change in Financial Condition.

The Candidate CRR Holder or CRR Holder that has been granted Unsecured Credit Limit has an ongoing obligation to inform the CAISO within five (5) Business Days of any Material Change in Financial Condition including but not limited to credit rating changes described in Section 12.1.1.3 of the CAISO Tariff.

4.10.2.2 Failure to Promptly Report a Material Change.

If a Candidate CRR Holder or CRR Holder fails to inform the CAISO of a material change in its information provided to the CAISO including a Material Change in Financial Condition, that may affect the Financial Security of the CAISO, the CAISO may suspend or terminate the Candidate CRR Holder or CRR Holder's rights under the CAISO Tariff in accordance with the terms of Section 12.3 of the CAISO Tariff and Section 4.10.4.2 of this Appendix, respectively. If the CAISO intends to terminate the Candidate CRR Holder's status, it shall file a notice of termination with FERC in accordance with the terms of the CRR Entity Agreement. Such termination shall be effective upon acceptance by FERC of a notice of termination in accordance with the terms of the CRR Entity Agreement.

4.10.3 Termination of a CRR Entity Agreement.

4.10.3.1 Prior Notice Requirements.

- (a) A CRR Entity Agreement may be terminated by the CAISO on written notice to the Candidate CRR Holder or CRR Holder that is a party to the CRR Entity Agreement in accordance with the terms of the CRR Entity Agreement:
 - (i) if the Candidate CRR Holder or CRR Holder no longer meets the requirements for eligibility set out in Section 4.10 of this Appendix and fails to remedy the default within a period of seven (7) days after the CAISO has given written notice of the default;
 - (ii) if the Candidate CRR Holder or CRR Holder fails to pay any sum under this CAISO Tariff and fails to remedy the default within a period of five (5) Business Days after the CAISO has given written notice of the default; or
 - (iii) if the Candidate CRR Holder or CRR Holder commits any other default under this CAISO Tariff or any of the Business Practice Manuals which, if capable of being remedied, is not remedied within thirty (30) days after the CAISO has given it written notice of the default.
- (b) The Candidate CRR Holder or CRR Holder may terminate its CRR Entity Agreement in accordance with the provisions of that agreement.
- (c) Upon termination of the CRR Entity Agreement, Candidate CRR Holders or CRR Holders shall continue to be liable for any outstanding financial or other obligations incurred under the CAISO Tariff as a result of their status as a Candidate CRR Holder or CRR Holder.

- (d) The CAISO shall, following termination of a CRR Entity Agreement and within thirty (30) days of being satisfied that no sums remain owing by the Candidate CRR Holder or CRR Holder under the CAISO Tariff, return or release to the Candidate CRR Holder or CRR Holder, as appropriate, any Financial Security support provided by such Candidate CRR Holder or CRR Holder to the CAISO under Sections 12.1 and 12.6 of the CAISO Tariff.

4.10.3.2 Suspension of Registration and Qualification

Pending FERC acceptance of termination of service pursuant to the filing of a notice of termination of the CRR Entity Agreement, the CAISO will suspend the registration and qualification of a Candidate CRR Holder or CRR Holder that has received a notice of termination under the CRR Entity Agreement and the Candidate CRR Holder will not be able to submit nominations in the CRR Allocation or bids in the CRR Auction, or to register as a CRR Holder in the Secondary Registration System.

[NOT USED]

PART E. PRO FORMA CRR ENTITY AGREEMENT

The provisions of this Part E are necessary to enable the CAISO to establish the terms of a *pro forma* service agreement by which the CASIO will enter into a direct relationship with entities that desire to participate in the CRR Allocation and CRR Auction to be conducted in the summer and fall of 2007.

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

AND

[CONGESTION REVENUE RIGHTS ENTITY]

CRR ENTITY AGREEMENT

CRR ENTITY AGREEMENT

THIS AGREEMENT is dated this ____ day of _____, _____, and is entered into, by and between:

(1) **[Full Legal Name]** having its registered and principal place of business located at **[Address]** (the "CRR Entity");

and

(2) **California Independent System Operator Corporation**, a California nonprofit public benefit corporation having a principal executive office located at such place in the State of California as the CAISO Governing Board may from time to time designate, initially 151 Blue Ravine Road, Folsom, California 95630 (the "CAISO").

The CRR Entity and the CAISO are hereinafter referred to individually as a "Party" and collectively as the "Parties."

Whereas:

- A.** The CAISO Tariff provides that any entity that holds or intends to hold CRRs must register and qualify with the CAISO and comply with the terms of the CAISO Tariff, regardless of whether they are to acquire CRRs through the CRR Allocation or CRR Auction, or through the Secondary Registration System.
- B.** The CRR Entity has completed the Candidate CRR Holder application process and is eligible to participate in the CRR Allocation or CRR Auction or register as a CRR Holder through the Secondary Registration System.
- C.** The CAISO Tariff further provides that any entity who wishes to participate in the CRR Allocation or CRR Auction or register as a CRR Holder through the Secondary Registration System must meet all of the Candidate CRR Holder requirements and creditworthiness provisions in the CAISO Tariff and the relevant Business Practice Manual, including demonstration of its ability to accommodate the financial responsibility associated with holding CRRs.
- D.** The CRR Entity intends to obtain CRRs either through the CRR Allocation or CRR Auction or to register as a CRR Holder through the Secondary Registration System and, therefore, wishes to undertake to the CAISO that it will comply with the applicable provisions of the CAISO Tariff.
- E.** The Parties are entering into this Agreement in order to establish the terms and conditions pursuant to which the CAISO and the CRR Entity will discharge their respective duties and responsibilities under the CAISO Tariff.

NOW THEREFORE, in consideration of the mutual covenants set forth herein, **THE PARTIES AGREE** as follows:

**ARTICLE I
DEFINITIONS AND INTERPRETATION**

- 1.1 Master Definitions Supplement.** All terms and expressions used in this Agreement shall have the same meaning as those contained in the Master Definitions Supplement in Appendix A of the CAISO Tariff.
- 1.2 Rules of Interpretation.** The following rules of interpretation and conventions shall apply to this Agreement:
- (a) if there is any inconsistency between this Agreement and the CAISO Tariff, the CAISO Tariff will prevail to the extent of the inconsistency;
 - (b) the singular shall include the plural and vice versa;
 - (c) the masculine shall include the feminine and neutral and vice versa;
 - (d) "includes" or "including" shall mean "including without limitation";
 - (e) references to a Section, Article, or Schedule shall mean a Section, Article, or a Schedule of this Agreement, as the case may be, unless the context otherwise requires;
 - (f) a reference to a given agreement 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;
 - (g) unless the context otherwise requires, references to any law shall be deemed references to such law as it may be amended, replaced, or restated from time to time;
 - (h) unless the context otherwise requires, any reference to a "person" includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization, or other entity, in each case whether or not having separate legal personality;
 - (i) unless the context otherwise requires, any reference to a Party includes a reference to its permitted successors and assigns;
 - (j) any reference to a day, week, month, or year is to a calendar day, week, month, or year; and
 - (k) the captions and headings in this Agreement are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Agreement.

**ARTICLE II
ACKNOWLEDGEMENTS OF CRR ENTITY AND CAISO**

- 2.1 Scope of Application to Parties.** The CRR Entity and CAISO acknowledge that all Candidate CRR Holders or CRR Holders must sign this Agreement in accordance with section 4.10.1.9.1 of the CAISO Tariff.

**ARTICLE III
TERM AND TERMINATION**

- 3.1 Effective Date.** This Agreement shall be effective as of the later of the date it is executed by both Parties or the date accepted for filing and made effective by FERC if such FERC filing is required, and shall remain in full force and effect until terminated pursuant to Section 3.2 of this Agreement.
- 3.2 Termination**
- 3.2.1 Termination by CAISO.** Subject to Article V, the CAISO may terminate this Agreement by giving written notice to the CRR Entity of termination in the event that the CRR Entity commits any material default under this Agreement and/or the CAISO Tariff as it pertains to this Agreement which, if capable of being remedied, is not remedied within thirty (30) days after the CAISO has given, to the CRR Entity, written notice of the default, unless excused by reason of Uncontrollable Forces in accordance with Article X of this Agreement or unless the CAISO agrees, in writing, to an extension of the time to remedy such material default. With respect to any notice of termination given pursuant to this Section, the CAISO must file a timely notice of termination with FERC, if this Agreement was filed with FERC, or must otherwise comply with the requirements of FERC Order No. 2001 and related FERC orders. The filing of the notice of termination by the CAISO with FERC will be considered timely if: (1) the filing of the notice of termination is made after the preconditions for termination have been met and (2) the CAISO files the notice of termination within sixty (60) days after issuance of the notice of default or (3) the CAISO files the notice of termination in accordance with the requirements of FERC Order No. 2001. This Agreement shall terminate upon acceptance by FERC of such a notice of termination, if filed with FERC, or thirty (30) days after the date of the CAISO's notice of default, if terminated in accordance with the requirements of FERC Order No. 2001 and related FERC orders.
- 3.2.2 Termination by CRR Entity.** In the event that the CRR Entity is no longer a CRR Holder, it may terminate this Agreement, on giving the CAISO not less than ninety (90) days' written notice; provided, however any outstanding financial right or obligation or any other obligation under the CAISO Tariff of the Candidate CRR Holder or CRR Holder that have arisen while the CRR Entity was a Candidate CRR Holder or a CRR Holder, and any provision of this Agreement necessary to give effect to such right or obligation shall survive until satisfied. With respect to any notice of termination given pursuant to this Section, the ISO must file a timely notice of termination with FERC, if this Agreement has been filed with FERC, or must otherwise comply with the requirements of FERC Order No. 2001 and related FERC orders. The filing of the notice of termination by the CAISO with FERC will be considered timely if: (1) the request to file a notice of termination is made after the preconditions for termination have been met and (2) the CAISO files the notice of termination within sixty (60) days after receipt of such request or (3) the CAISO files the notice of termination in accordance with the requirements of FERC Order No. 2001. This Agreement shall terminate upon acceptance by FERC of such a notice of termination, if such notice is required to be filed with FERC, or upon ninety (90) days after the CAISO's receipt of the CRR Entity's notice of termination, if terminated in accordance with the requirements of FERC Order No. 2001 and related FERC orders.

**ARTICLE IV
GENERAL TERMS AND CONDITIONS**

- 4.1 CRR Holder Requirements.** The CRR Entity must register and qualify with the CAISO and comply with all terms of the CAISO Tariff applicable to Candidate CRR Holders or CRR Holders, regardless of the manner in which they acquire CRRs whether by CRR Allocation, CRR Auction, or through the Secondary Registration System.
- 4.2 CRR Holder Creditworthiness Requirements.** The CRR Entity must comply with the requirements for creditworthiness applicable to Candidate CRR Holders or CRR Holders, including the creditworthiness provisions of the CAISO Tariff and the relevant Business Practice Manual.
- 4.3 Settlement Account.** The CRR Entity shall maintain at all times an account with a bank capable of Fed-Wire transfer to which credits or debits shall be made in accordance with the billing and Settlement provisions of Section 11 of the CAISO Tariff. Such account shall be the account referred to in Schedule 2 hereof or as notified by the CRR Entity to the CAISO from time to time by giving at least seven (7) days written notice before the new account becomes operational. Such changes to Schedule 2 shall not constitute an amendment to this Agreement.
- 4.4 Electronic Contracting.** All submitted applications, bids, confirmations, changes to information on file with the CAISO and other communications conducted via electronic transfer (e.g., direct computer link, FTP file transfer, bulletin board, e-mail, facsimile or any other means established by the CAISO) shall have the same legal rights, responsibilities, obligations and other implications as set forth in the terms and conditions of the CAISO Tariff as if executed in written format.
- 4.5 Agreement Subject to CAISO Tariff.** The Parties will comply with all provisions of the CAISO Tariff applicable to Candidate CRR Holders or CRR Holders. This Agreement shall be subject to the CAISO Tariff, which shall be deemed to be incorporated herein.

**ARTICLE V
PERFORMANCE**

- 5.1 Penalties.** The CRR Entity shall be subject to all penalties made applicable to Candidate CRR Holders and CRR Holders set forth in the CAISO Tariff. Nothing in this Agreement, with the exception of the provisions relating to ADR, shall be construed as waiving the rights of the CRR Entity to oppose or protest the specific imposition by the CAISO of any FERC-approved penalty on the CRR Entity.
- 5.2 Corrective Measures.** If the CRR Entity of the CAISO fails to meet or maintain the requirements set forth in this Agreement and/or the CAISO Tariff as it pertains to this Agreement, the CAISO or the CRR Entity shall be permitted to take any of the measures, contained or referenced in the CAISO Tariff, which the Party seeking enforcement deems to be necessary to correct the situation.

**ARTICLE VI
COSTS**

- 6.1 Operating and Maintenance Costs.** The CRR Entity shall be responsible for all its costs incurred in connection with all its CRR related activities.

**ARTICLE VII
DISPUTE RESOLUTION**

- 7.1 Dispute Resolution.** The Parties shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. In the event any dispute is not settled, the Parties shall adhere to the ISO ADR Procedures set forth in Section 13 of the CAISO Tariff, which is incorporated by reference, except that any reference in Section 13 of the CAISO Tariff to Market Participants shall be read as a reference to the CRR Entity and references to the CAISO Tariff shall be read as references to this Agreement.

**ARTICLE VIII
REPRESENTATIONS AND WARRANTIES**

- 8.1 Representation and Warranties.** Each Party represents and warrants that the execution, delivery and performance of this Agreement by it has been duly authorized by all necessary corporate and/or governmental actions, to the extent authorized by law.

**ARTICLE IX
LIABILITY**

- 9.1 Liability.** The provisions of Section 14 of the CAISO Tariff will apply to liability arising under this Agreement, except that all references in Section 14 of the CAISO Tariff to Market Participants shall be read as references to the CRR Entity and references to the CAISO Tariff shall be read as references to this Agreement.

**ARTICLE X
UNCONTROLLABLE FORCES**

- 10.1 Uncontrollable Forces Tariff Provisions.** Section 14.1 of the CAISO Tariff shall be incorporated by reference into this Agreement except that all references in Section 14.1 of the CAISO Tariff to Market Participants shall be read as a reference to the CRR Entity and references to the CAISO Tariff shall be read as references to this Agreement.

**ARTICLE XI
MISCELLANEOUS**

- 11.1 Assignments.** Either Party may assign or transfer any or all of its rights and/or obligations under this Agreement with the other Party's prior written consent in accordance with Section 22.2 of the

CAISO Tariff and other CAISO Tariff requirements as applied to Candidate CRR Holders or CRR Holders. Such consent shall not be unreasonably withheld. Any such transfer or assignment shall be conditioned upon the successor in interest accepting the rights and/or obligations under this Agreement as if said successor in interest was an original Party to this Agreement.

- 11.2 Notices.** Any notice, demand, or request which may be given to or made upon either Party regarding this Agreement shall be made in accordance with Section 22.4 of the CAISO Tariff. A Party must update the information in Schedule 1 of this Agreement as information changes. Such changes to Schedule 1 shall not constitute an amendment to this Agreement.
- 11.3 Waivers.** Any waivers at any time by either 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.
- 11.4 Governing Law and Forum.** This Agreement shall be deemed to be a contract made under, and for all purposes shall be governed by and construed in accordance with, the laws of the State of California, except its conflict of law provisions. The Parties irrevocably consent that any legal action or proceeding arising under or relating to this Agreement to which the ISO ADR Procedures do not apply, shall be brought in any of the following forums, as appropriate: (i) any court of the State of California, (ii) any federal court of the United States of America located in the State of California, except to the extent subject to the protections of the Eleventh Amendment of the United States Constitution or, (iii) where subject to its jurisdiction, before the Federal Energy Regulatory Commission.
- 11.5 Consistency with Federal Laws and Regulations.** This Agreement shall incorporate by reference Section 22.9 of the CAISO Tariff as if the references to the CAISO Tariff were referring to this Agreement.
- 11.6 Merger.** This Agreement constitutes the complete and final agreement of the Parties with respect to the subject matter hereto and supersedes all prior agreements, whether written or oral, with respect to such subject matter.
- 11.7 Severability.** If any term, covenant, or condition of this Agreement or the application or effect of any such term, covenant, or condition is held invalid as to any person, entity, or circumstance, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in force and effect to the maximum extent permitted by law, and all other terms, covenants, and conditions of this Agreement and their application shall not be affected thereby, but shall remain in force and effect and the Parties shall be relieved of their obligations only to the extent necessary to eliminate such regulatory or other determination unless a court or governmental agency of competent jurisdiction holds that such provisions are not separable from all other provisions of this Agreement.
- 11.8 Section Headings.** Section headings provided in this Agreement are for ease of reading and are not meant to interpret the text in each Section.

11.9 Amendments. This Agreement and the Schedules attached hereto may be amended from time to time by the mutual agreement of the Parties in writing. Amendments that require FERC approval shall not take effect until FERC has accepted such amendments for filing and made them effective. If the amendment does not require FERC approval, the amendment will be filed with FERC for informational purposes. Nothing herein shall be construed as affecting in any way the right of the CAISO to make unilateral application to FERC for a change in the rates, terms, and conditions of this Agreement under Section 205 of the FPA and pursuant to FERC's rules and regulations promulgated thereunder. The standard of review the Commission shall apply when acting upon proposed modifications to this Agreement by the CAISO shall be the "just and reasonable" standard of review rather than the "public interest" standard of review. The standard of review the Commission shall apply when acting upon proposed modifications to this Agreement by the Commission's own motion or by a signatory other than the CAISO or non-signatory entity shall also be the "just and reasonable" standard of review. Schedules 1 and 2 are provided for informational purposes and revisions to those schedules do not constitute a material change in the Agreement warranting Commission review.

11.10 Counterparts. This Agreement may be executed in one or more counterparts at different times, each of which shall be regarded as an original and all of which, taken together, shall constitute one and the same Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed on behalf of each by and through their authorized representatives as of the date hereinabove written.

California Independent System Operator Corporation

By: _____

Name: _____

Title: _____

Date: _____

[Name of CRR Entity]

By: _____

Name: _____

Title: _____

Date: _____

SCHEDULE 1

NOTICES
[Section 11.2]

CRR Entity

Name of Primary

Representative: _____

Title: _____

Company: _____

Address: _____

City/State/Zip Code: _____

Email Address: _____

Phone: _____

Fax No: _____

Name of Alternative

Representative: _____

Title: _____

Company: _____

Address: _____

City/State/Zip Code: _____

Email Address: _____

Phone: _____

Fax No: _____

CAISO

Name of Primary

Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email address: _____

Phone: _____

Fax: _____

Name of Alternative

Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email address: _____

Phone: _____

Fax: _____

SCHEDULE 2
SETTLEMENT ACCOUNT
[SECTION 4.3]

CRR Entity Account Information

Settlement Account No:

Title:

Sort Code:

Bank:

PART F. MISCELLANEOUS SECTIONS

27.2 Load Aggregation Points (LAP).

The CAISO shall create Load Aggregation Points and shall maintain Default LAPs at which all Demand shall Bid and be settled, except as provided in Section 27.2.1 and Section 30.5.3.2 of this Appendix.

27.2.1 Metered Subsystems.

The CAISO shall define specific MSS-LAPs for each MSS. The MSS LAP shall be made up the PNodes within the MSS that have Load served off of those Nodes. The MSS-LAPs have unique Load Distribution Factors that reflect the distribution of the MSS Demand to the network nodes within the MSS. These MSS LAPs are separate from the Default LAPs, and the load distribution factors of the Default LAP do not reflect any MSS Load.

30.5.3.2 Exceptions to Requirement for Submission of Demand Bids and Settlement at the LAP.

The following are exceptions to the requirement that Demand Bids be submitted and settled at the LAP:

- (a) ETC or TOR Self-Schedules submitted consistent with the submitted TRTC Instructions;
- (b) Participating Load Bids for Supply and Demand may be submitted and settled at a PNode; and
- (c) Export Bids are submitted and settled at Scheduling Points, which do not constitute a LAP.

PART G. DEFINITIONS

Unless defined in this Appendix BB or the context otherwise requires, all capitalized terms and expressions used in this Appendix BB shall have the meaning as defined in the Master Definitions Supplement in Appendix A. The following capitalized terms and expressions used in this Appendix BB shall have the meanings set forth below unless otherwise stated or the context otherwise requires. If two or more capitalized terms are used together in a manner not uniquely defined in Appendix A or this Appendix BB, the meanings of each defined term apply.

Aggregated PNodes	A Load Aggregation Point, Trading Hub or any group of Pricing Nodes as defined by the CAISO.
Bid	An offer for the Supply or Demand of Energy or Ancillary Services, including Self-Schedules, submitted by Scheduling Coordinators for specific resources, conveyed through several components that apply differently to the different types of service offered to or demanded from any of the CAISO Markets.
Business Practice Manual (BPM)	A collection of documents made available by the CAISO on the CAISO Website that contain the rules, policies, procedures and guidelines established by the CAISO for operational, planning, accounting and settlement requirements of CAISO Market activities, consistent with the CAISO Tariff.
CAISO	The California Independent System Operator Corporation, a California non-profit public benefit corporation that operates the transmission facilities of all Participating TOs and dispatches certain Generating Units and Loads
CAISO Markets	Any of the markets administered by the CAISO under the CAISO Tariff, including, without limitation, the DAM, HASP, RTM, Transmission, and Congestion Revenue Rights.
Candidate CRR Holder	An entity that is registered and qualified by the CAISO to participate in the CRR Allocation, the CRR Auction or in the Secondary Registration System to become a CRR Holder and is a party to a fully executed CRR Entity Agreement, and therefore must comply with the requirements for Candidate CRR Holders under the CAISO Tariff.

Congestion Charge	A charge attributable to the Marginal Cost of Congestion at a given pricing PNode.
CRR Allocation	The process of nominations and awards held monthly and annually through which the CAISO will distribute CRRs to Candidate CRR Holders.
CRR Auction	The annual and monthly market process that will follow CRR Allocation through which the CAISO makes CRRs available to Candidate CRR Holders that submit offers to purchase CRRs.
CRR Eligible Quantity	The Seasonal CRR Eligible Quantity or the Monthly CRR Eligible Quantity.
CRR Entity Agreement	An agreement between the CAISO and a Candidate CRR Holder or CRR Holder that must be fully executed in order for such an entity to participate in the CRR Allocation, CRR Auction, or Secondary Registration System, a <i>pro forma</i> of which is set forth in Part E of this Appendix.
CRR Holder	A Candidate CRR Holder that has acquired CRR(s) either through the CRR Allocation, the CRR Auction, or through a transaction registered in the Secondary Registration System.
CRR Load Metric	The Seasonal CRR Load Metric or Monthly CRR Load Metric.
CRR Obligations	A financial instrument that entitles the holder to a CRR Payment when Congestion is in the direction of the CRR Source to CRR Sink specification and imposes on its holder a CRR Charge when Congestion is in the opposite direction of the CRR Source to CRR Sink specification.
CRR Payment	A payment from the CAISO to a CRR Holder.
CRR Sink	A PNode or a Trading Hub specified as the point of withdrawal for a Congestion Revenue Right.
CRR Source	A PNode or a Trading Hub specified as the point of receipt for a Congestion Revenue Right.
Custom Load Aggregation Point (Custom LAP)	An aggregation of Load PNodes created by the CAISO based on a set of custom LDFs submitted by an SC, at which such SC may submit a single Bid and settle Demand consistent with the CAISO Tariff rules, and for which the SC is required to submit to the CAISO metered data for the nodal Load represented in such aggregation
Day-Ahead	The twenty-four hour time period prior to the Trading Day.

Day-Ahead Market (DAM)	A series of processes conducted in the Day-Ahead that includes the Market Power Mitigation-Reliability Requirement Determination, the Integrated Forward Market and the Residual Unit Commitment.
Default LAP	The LAP defined for the TAC Area at which all Bids for Demand shall be submitted and settled, except as provided in Sections 27.2.1 and 30.5.3.2 of this Appendix.
ETC Self-Schedule	Self-Schedules submitted by Scheduling Coordinators pursuant to Existing Rights as reflected in the TRTC Instructions.
Existing Zone Generation Trading Hub	Trading Hubs specifically developed to represent the average price paid to generation resources within Existing Zones.
Existing Zone	Regions formally referred to as NP15, SP15, and ZP26 prior to implementation of the CAISO LMP market design.
Full Network Model (FNM)	A computer-based model that includes all CAISO Control Area transmission network (load and generation) busses, transmission constraints, and interface busses between the CAISO Control Area and adjacent Control Areas. The FNM models the transmission facilities internal to the CAISO Control Area as elements of a looped network and models the CAISO Control Area interties with adjacent Control Areas in a radial fashion.
Hour Ahead Scheduling Process (HASP)	The process conducted by the CAISO beginning at seventy-five minutes prior to the Trading Hour through which the CAISO conducts the following activities: 1) accepts Bids for Supply of Energy, including imports, exports and Ancillary Services imports to be supplied during the next Trading Hour that apply to the MPM-RRD, RTUC, STUC, and RTD; 2) conducts the MPM-RRD on the Bids that apply to the RTUC, STUC, and RTD; and 3) conducts the RTUC for the hourly pre-dispatch of Energy and Ancillary Services.
Integrated Forward Market (IFM)	The pricing run conducted by the CAISO using a security constrained unit commitment in the Day-Ahead Market, after the MPM-RRD process, which includes unit commitment, Ancillary Service procurement, Congestion Management and Energy procurement based on Supply and Demand Bids.
Load Aggregation Point	A set of Pricing Nodes as specified in Section 27.2 of this Appendix that are used for the submission of Bids and Settlement of Demand.

Load Distribution Factors (LDF)	A number that reflects the relative amount of Load at each PNode within a Load Aggregation Point. Load Distribution Factors determine how the aggregated Load at a given LAP is distributed to the associated power system Nodes. The sum of all Load Distribution Factors for a single Load Aggregation Point equals one.
Long Term CRR	A Congestion Revenue Right differentiated by season and time-of-use period (on-peak and off-peak) with a term of ten years.
Marginal Cost of Congestion (MCC)	The component of LMP at a PNode that accounts for the cost of congestion, as measured between that Node and a Reference Bus.
Marginal Cost of Losses (MCL)	The component of LMP at a PNode that accounts for the marginal real power losses, as measured between that Node and a Reference Bus.
Market Power Mitigation - Reliability Requirement Determination (MPM-RRD)	The two-optimization run process conducted in both the Day-Ahead Market and the HASP that determines the need for the CAISO to employ market power mitigation measures or Dispatch RMR Units.
Monthly CRR Eligible Quantity	The MW quantity of CRRs an LSE is eligible to nominate for the relevant month in a monthly CRR Allocation.
Monthly CRR Load Metric	<i>The load metric used for determining eligibility for CRR Allocation as provided in Section 36.8.2.2 of this Appendix BB.</i>
MSS Aggregator	An entity that has executed an agreement with the CAISO that enables it to represent individual MSS Operators in the CAISO Markets on an aggregated basis, which agreement has been accepted by FERC.
Pricing Node (PNode)	A single network Node or subset of network Nodes where a physical injection or withdrawal is modeled and for which a Locational Market Price is calculated and used for financial settlements.
Pumped-Storage Hydro Units	Hydroelectric dam with capability to produce electricity by pumping water between reservoirs at different elevations.
Real-Time Market (RTM)	The spot market conducted by the CAISO using SCUC and SCED in the Real-Time, after the HASP is completed for the purpose of unit commitment, Ancillary Service procurement, Congestion Management and Energy procurement based on Supply Bids and CAISO Forecast of CAISO Demand.
Reference Bus	The Location(s) on the CAISO Controlled Grid relative to which mathematical quantities relating to powerflow solution will be calculated.

Residual Unit Commitment (RUC)	The process conducted by the CAISO in the Day-Ahead Market after the IFM has been executed to ensure sufficient Generating Units, System Units, System Resources and Participating Loads are committed to meet the CAISO Forecast of CAISO Demand.
Seasonal CRR	A Congestion Revenue Right that is valid for one season and one time-of-use period in a given year.
Seasonal CRR Eligible Quantity	The MW quantity of CRRs an LSE is eligible to nominate for the relevant season in the annual CRR Allocation.
Seasonal CRR Load Metric	The MW level of Load that is exceeded only in 0.5 percent of the hours for each season and time of use period based on the LSE's historical Load.
Secondary Registration System	The computer interface through which CRR Holders and Candidate CRR Holders register any bilateral CRR transactions with the CAISO.
Self-Schedule	The Bid component that indicates the quantities in MWhs with no specification of a price that the Scheduling Coordinator is submitting to the CAISO, which indicates that the Scheduling Coordinator is a Price Taker, Regulatory Must-Run Generation or Regulatory Must-Take Generation, which includes ETC and TOR Self-Schedules and Self-Schedules for Converted Rights.
Simultaneous Feasibility Test ("SFT")	The process that the CAISO will conduct to ensure that allocated and auction CRRs do not exceed relevant transmission system constraints.
TOR Self-Schedule	Self-Schedules submitted by Scheduling Coordinators pursuant to Transmission Ownership Rights as reflected in the TRTC Instructions.
Trading Hub	An aggregation of network Pricing Nodes, such as Existing Zone Generation Trading Hubs, maintained and calculated by the CAISO for settlement and trading purposes posted by the CAISO on its CAISO Website.
Transmission Rights and Transmission Curtailment (TRTC) Instructions	Operational directives developed between Existing Rights holders and the Participating TO, submitted to the CAISO by the Participating TO, unless otherwise agreed to by the Participating TO and the Existing Rights holder to facilitate the accommodation of Existing Rights in the CAISO Markets.

Adjusted Load Metric	A Load Serving Entity's Load Metric minus the megawatts of Load served using Existing Transmission Contracts, Converted Rights, and Transmission Ownership Rights.
Adjusted Verified CRR Source Quantity	The MW amount eligible for nomination by an LSE or Qualified OCALSE in a verified tier of the CRR Allocation process, determined by reducing a Verified CRR Source Quantity to account for circumstances where the ownership or contract right to a generating resource is effective only for a portion of a particular season or month for which CRRs are being nominated.
CAISO	See ISO in Appendix A.
CAISO Controlled Grid	The system of transmission lines and associated facilities of the Participating TOs that have been placed under the CAISO's Operational Control.
CAISO Tariff	The California Independent System Operator Corporation Operating Agreement and Tariff, dated March 31, 1997, as it may be modified from time to time.
CAISO Website	The CAISO internet home page at http://www.aiso.com / or such other internet address as the CAISO shall publish from time to time.
CRR Balancing Account	The financial account held by the CAISO for CRRs.
CRR Charge	The Charge assessed by the CAISO on the holder of a CRR Obligation when Congestion is in the opposite direction of the CRR Source to CRR Sink specification.
CRR Year Four	<i>Second, third and fourth quarters of calendar year 2011 and first quarter of calendar year 2012.</i>
CRR Year One	<i>Second, third and fourth quarters of calendar year 2008 and first quarter of calendar year 2009.</i>
CRR Year Three	<i>Second, third and fourth quarters of calendar year 2010 and first quarter of calendar year 2011.</i>
CRR Year Two	<i>Second, third and fourth quarters of calendar year 2009 and first quarter of calendar year 2010.</i>
Existing Transmission Contract (ETC) or Existing Contracts	The contracts which grant transmission service rights in existence on the CAISO 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.

Fixed CRRs

Congestion Revenue Rights that are used in the running of an SFT to represent known encumbrances on the transmission system and which may include some or all of the following: previously allocated or awarded Monthly, Seasonal, Long Term, and Merchant Transmission CRRs, Existing Transmission Contracts, and Converted Rights.

Inter-SC Trade

A trade between Scheduling Coordinators of Energy or Ancillary Services in accordance with the CAISO Tariff.

Load Migration

The transfer of the responsibility to serve Load from one Load Serving Entity to another.

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, that (a) (i) serves End Users within the CAISO Control Area and (ii) 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 CAISO Control Area; (b) is a federal power marketing authority that serves End Users; or (c) is the State Water Resources Development System commonly known as the State Water Project of the California Department of Water Resources.

Merchant Transmission CRRs

Incremental CRRs that are created by the addition of a Merchant Transmission Facility. Merchant Transmission CRRs are effective for thirty (30) years or for the pre-specified intended life of the facility, whichever is less.

Merchant Transmission Facility

A transmission facility or upgrade that is part of the CAISO Controlled Grid and whose costs are paid by a Project Sponsor that does not recover the cost of the transmission investment through the CAISO's Access Charge or WAC or other regulatory cost recovery mechanism.

Monthly CRR

A Congestion Revenue Right whose term is one calendar month in length and distributed in the monthly CRR Allocation and monthly CRR Auction.

Multi-Point CRR

A CRR Obligation specified according to one or more CRR Sources and one or more CRR Sinks and a flow from the CRR Source(s) to the CRR Sink(s), provided that at least the CRR Sink or the CRR Source identifies more than one point.

Offsetting CRR

One of the pair of new equal and opposite CRRs created and allocated by the CAISO to reflect Load Migration between two LSEs pursuant to the provisions in Section 36.8.5 of this Appendix, which is allocated to the Load losing LSE and is opposite in direction to the corresponding CRR previously allocated to that LSE and is denominated in a MW quantity that reflects the net amount of Load Migration between the two LSEs.

Out-of-Control Area Load Serving Entity (OCALSE)

An entity serving end-users located outside the CAISO Control Area and that has been granted authority or has an obligation pursuant to Federal, State or local law, or under contracts to provide electric service to such end-users located outside the CAISO Control Area.

PMax

The maximum normal capability of the Generating Unit. PMax should not be confused as an emergency rating of the Generating Unit.

PNP Eligible Quantity

The maximum MW quantity of CRRs an LSE is eligible to nominate in the Priority Nomination Process of the CRR Allocation.

Point-to-Point CRR

A CRR Option or CRR Obligation with a single CRR Source to a single CRR Sink.

Priority Nomination Process (PNP)

The step in an annual CRR Allocation in years beyond CRR Year One through which CRR Holders re-nominate (1) Seasonal CRRs they were allocated in the prior year, (2) Long Term CRRs that are expiring, and (3) Existing Transmission Contracts and Converted Rights that are expiring.

Qualified OCALSE

An OCALSE which the CAISO has certified has met all the requirements for eligibility for CRR Allocation in accordance with Section 36.9 of this Appendix.

Real-Time Interchange Export Schedule

An agreement to transfer Energy from the CAISO Control Area to a interconnected Control Area at a Scheduling Point based on agreed-upon size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and Energy between the source and sink Control Areas involved in the transaction.

Seasonal Available CRR Capacity The upper limit of network capacity that will be used in the annual CRR Allocation and annual CRR Auction calculated by effectively reducing OTC for Transmission Ownership Rights as if all lines will be in service for the relevant year.

Sub-LAP A CAISO defined subset of PNodes within a Default LAP.

Tier LT The tier of the annual CRR Allocation process through which the CAISO allocates Long Term CRRs.

Verified CRR Source Quantity The MW amount corresponding to a verified CRR Source and the LSE or OCALSE that submitted that verified CRR Source to the CAISO, as described in Section 36.8.3.4 of this Appendix.

PART H. CONGESTION REVENUE RIGHTS

36 Congestion Revenue Rights.

36.1 Overview of CRRs and Procurement of CRRs.

The CAISO distributes CRRs through an allocation and auction process as described in this Section 36. CRR Holders and Market Participants eligible to become CRR Holders can also buy, sell, or trade CRRs bilaterally as described in Section 36.7 of this Appendix.

36.2 Types of CRR Instruments.

CRRs can be CRR Obligations or CRR Options. Each CRR is fully specified by its type (CRR Obligation or CRR Option), its CRR Source(s), its CRR Sink(s), its MW quantity, and the Trading Hours for which it is valid. The CRR Source(s) and CRR Sink(s) determine the direction of the CRR, which is from CRR Source(s) to CRR Sink(s).

36.2.1 CRR Obligations.

A CRR Obligation entitles its holder to receive a CRR Payment if the Congestion in a given Trading Hour is in the same direction as the CRR Obligation, and requires the CRR Holder to pay a CRR Obligation charge if the Congestion in a given Trading Hour is in the opposite direction of the CRR. The CRR Payment or CRR Obligation charge is equal to the per-MWh cost of Congestion (which equals the MCC at the CRR Sink minus the MCC at the CRR Source) multiplied by the MW quantity of the CRR.

36.2.2 CRR Options.

A CRR Option entitles its CRR Holder to a CRR Payment if the Congestion is in the same direction as the CRR Option, but requires no CRR Obligation charge if the Congestion is in the opposite direction of the CRR. The CRR Payment is equal to the per-MWh cost of Congestion (which equals the MCC at the CRR Sink minus the MCC at the CRR Source, when this quantity is positive and zero otherwise) multiplied by the MW quantity of the CRR.

36.2.3 Point-to-Point CRRs.

A Point-to-Point CRR is a CRR Option or CRR Obligation defined from a single CRR Source to a single CRR Sink.

36.2.4 Multi-Point CRRs.

A Multi-Point CRR is a CRR Obligation defined by more than one CRR Source and/or more than one CRR Sink, plus a specified distribution of the total MW value of the CRR over the multiple CRR Sources and/or multiple CRR Sinks such that the total MW assigned to all CRR Sources equals the total MW assigned to all CRR Sinks equals the MW value of the CRR. For the allocation of CRRs under this Section 36, an LSE seeking to be allocated a Multi-Point CRR must specify a single CRR Sink in its nomination.

36.2.5 Monthly CRRs.

Monthly CRRs have a term of one month, are differentiated by time of use periods (on-peak and off-peak), and are available through the monthly CRR Allocation and CRR Auction processes in advance of each month.

36.2.6 Seasonal CRRs.

Seasonal CRRs have a term of three months, and are differentiated by the different time of use periods (on-peak and off-peak) for each day within a season. Seasonal CRRs are made available through the annual CRR Allocation and CRR Auction processes conducted each year prior to the year in which the Seasonal CRR applies.

36.2.7 Long Term CRRs.

Long Term CRRs have a term of ten years. Long Term CRRs are seasonal and are differentiated by the different time of use periods (on-peak and off-peak) for each day within a season. When Long Term CRRs are nominated and allocated they apply to the same season and time of use period for each year of the ten-year term and represent binding ten-year commitments by the CRR Holders that hold Long Term CRRs. Long Term CRRs are nominated and allocated to LSEs in Tier LT that is one tier in the sequence of tiers in the annual CRR Allocation process. Long Term CRRs are not available through the CRR Auction.

36.2.8 Full Funding of CRRs.

All CRRs will be fully funded; provided however, that full funding of CRRs will be suspended if a System Emergency as described in Section 7.7.4, an Uncontrollable Force as described in Section 14, or a Participating TO's withdrawal of facilities or Entitlements from the CAISO Controlled Grid as described in Section 36.8.7 of this Appendix leaves the CAISO with inadequate revenues.

36.3 CRR Specifications.

36.3.1 Quantity.

CRRs are distributed and settled in no less than one-**thousandth** of a MW denomination.

36.3.2 Term.

CRRs are Monthly CRRs, Seasonal CRRs, Long Term CRRs or Merchant Transmission CRRs. For CRR purposes, the applicable seasons are conventional calendar quarters as defined in the Business Practice Manual.

36.3.3 On-Peak and Off-Peak Specifications.

CRRs are defined either for on-peak or off-peak hours as specified by the CAISO in the applicable Business Practice Manuals consistent with the WECC standards at the time of the relevant CRR Allocation or CRR Auction.

36.4 FNM for CRR Allocation and CRR Auction.

When the CAISO conducts its CRR Allocation and CRR Auction, the CAISO shall use the most up-to-date DC FNM which is based on the AC FNM used in the Day-Ahead Market. The Seasonal Available CRR Capacity shall be based on the DC FNM, taking into consideration the following, all of which are discussed in the applicable Business Practice Manual: (i) any long-term scheduled transmission Outages, (ii) OTC adjusted for any long-term scheduled derates, and (iii) a downward adjustment due to TOR as determined by the CAISO. The Monthly Available CRR Capacity shall be based on the DC FNM, taking into consideration: (i) any scheduled transmission Outages known at least thirty (30) days in advance of the start of that month *as submitted for approval consistent with the criteria specified in Section 36.4.3 of this Appendix*, (ii) adjustments to compensate for the expected impact of Outages that are not required to be scheduled thirty (30) days in advance, including unplanned transmission Outages,

(iii) adjustments to restore Outages or derates that were applied for use in calculating Seasonal Available CRR Capacity but are not applicable for the current month, (iv) any new transmission facilities added to the CAISO Controlled Grid that were not part of the DC FNM used to determine the prior Seasonal Available CRR Capacity and that have already been placed in-service and energized at the time the CAISO starts the applicable monthly process, (v) OTC adjusted for any scheduled derates or Outages for that month, and (vi) a downward adjustment due to TOR as determined by the CAISO. For the first monthly CRR Allocation and CRR Auction for CRR Year One, to account for any planned or unplanned Outages that may occur for the first month of CRR Year One, the CAISO will derate all flow limits, including Transmission Interface limits and normal thermal limits, based on statistical factors determined as provided in the Business Practice Manuals.

36.4.1 Transmission Capacity Available for CRR Allocation and CRR Auction.

With the exception of the Tier LT, the CAISO makes available seventy-five percent (75%) of Seasonal Available CRR Capacity for the annual CRR Allocation and CRR Auction processes, and one hundred percent (100%) of Monthly Available CRR Capacity for the monthly CRR Allocation and CRR Auction processes. The CAISO makes available sixty percent (60%) of Seasonal Available CRR Capacity in the Tier LT. Available capacity at Scheduling Points shall be determined in accordance with Section 36.8.4.2 of this Appendix for the purposes of CRR Allocation and CRR Auction of CRRs that have a CRR Source identified at a Scheduling Point. Before commencing with the annual or monthly CRR Allocation and CRR Auction processes, the CAISO may distribute Merchant Transmission CRRs and will model those as fixed injections and withdrawals on the DC FNM to be used in the allocation and auction. These fixed injections and withdrawals are not modified by the Simultaneous Feasibility Test. Similarly, before commencing the annual or monthly CRR Allocation and CRR Auction processes, the CAISO will model any previously allocated Long Term CRRs as fixed injections and withdrawals on the DC FNM to be used in the CRR Allocation and CRR Auction. These fixed injections and withdrawals are not modified by the Simultaneous Feasibility Test, which will ensure no degradation of previously allocated and outstanding Long Term CRRs due to the CRR Allocation and CRR Auction processes. Maintaining the feasibility of allocated Long Term CRRs over the length of their terms also is accomplished through the transmission planning process in Section 24.1.3.

36.4.2 Simultaneous Feasibility.

The annual and monthly CRR Allocation processes release CRRs to fulfill CRR nominations as fully as possible subject to a Simultaneous Feasibility Test. To the extent that nominations are not simultaneously feasible, the nominations are reduced in accordance with the CRR Allocation optimization formulation until simultaneous feasibility is achieved. The CRR Allocation optimization formulation, detailed in the Business Practice Manuals, reduces nominated CRRs based on effectiveness in relieving overloaded constraints in order to minimize the total MW volume reduction of nominations while achieving simultaneous feasibility. In the event that there are two or more identical nominations for a specific combination of CRR Source and CRR Sink that affect an overloaded constraint, the CRR Allocation optimization formulation cannot distinguish these nominations based on effectiveness and, therefore, the CRR Allocation optimization formulation will award each such Candidate CRR Holder a pro rata share of the CRRs that can be awarded based on each Candidate CRR Holder's nominated MW amount. In addition to the adjustments in Section 36.4.1, the SFT for each CRR Allocation considers:

- a. CRRs representing ETCs, Converted Rights and any TOR capacity that was not captured in the adjustments described in Section 36.4 of this Appendix, which the CAISO deems necessary to prevent the Congestion Settlement of ETCs, Converted Rights, and TORs from causing revenue inadequacy of allocated and auctioned CRRs;
- b. In the case of the monthly CRR Allocation, the CRRs already released for that month in the annual CRR Allocation and Auction; and,
- c. The CRRs allocated in previous CRR Allocation tiers as described in Sections 36.8.3.1 through 36.8.3.6 of this Appendix.

In the event that transmission Outages and derates modeled for the monthly CRR Allocation and CRR Auction render previously issued Seasonal CRRs infeasible, the CAISO will increase the transfer capacity on the overloaded facilities just enough to render all Seasonal CRRs issued for the month feasible without creating any additional capacity beyond what is needed for the feasibility of the Seasonal CRRs. The CAISO will announce these adjustments to the market prior to conducting the monthly CRR Allocation and CRR Auction so that Candidate CRR Holders can take these facts into consideration in preparing their nominations and bids.

36.4.3 Scheduling Requirements for Outages that May Have a Significant Effect on CRR Revenue Adequacy.

As provided in Section 9.3.6.3.2 of the MRTU Tariff, Outages that may have a significant effect upon CRR revenue adequacy must be submitted for approval no less than thirty (30) days in advance of the first day of the month in which the Outage is proposed to begin. Outages that may have a significant effect upon CRR revenue adequacy are defined in terms of the type of facility and the planned duration of the Outage. Outages of the types of transmission facilities described below that extend beyond a twenty-four (24) hour period must be submitted for CAISO approval consistent with this 30-day advance submittal requirement. The types of transmission facilities on the CAISO Controlled Grid to which this 30-day advance submittal and approval requirement applies consist of transmission facilities that:

- (a) are rated above 200 kV; or
- (b) are part of any defined flow limit as described in a CAISO Operating Procedure;
- or
- (c) were out of service in the last three (3) years and for which the CAISO determined a special flow limit was needed for real-time operation.

A list of the transmission facilities that satisfy criteria (b) and (c) above is provided in the Operating Procedures. The list will be reviewed by the CAISO on an annual basis and revised as appropriate. The following types of Outages need not be submitted for approval within this thirty-day time frame and will not be designated as Forced Outages if they otherwise comply with the requirements in Section 9.3.6 of the MRTU Tariff: (1) Outages previously approved by CAISO that are moved within the same calendar month either by the CAISO or by request of the Participating TO; and (2) Outages associated with CAISO-approved allowable transmission maintenance activities during restricted maintenance operations as covered in CAISO Operating Procedures.

36.5 Candidate CRR Holder and CRR Holder Requirements.

Any entity that holds or intends to hold CRRs must register and qualify with the CAISO and comply with the other terms of this Section, regardless of whether they acquire CRRs by CRR Allocation, CRR Auction, or the Secondary Registration System, or are assigned CRRs for Load Migration.

36.5.1 Creditworthiness Requirements.

All CRR Holders and Candidate CRR Holders must comply fully with all creditworthiness requirements as provided in Section 12 of the CAISO Tariff and Section 12.6 of this Appendix and as further developed in the applicable Business Practice Manuals. The amount of available credit for participating in a CRR Auction cannot exceed the entity's Aggregate Credit Limit as provided in Section 12.

36.5.2 Required Training.

CRR Holders and Candidate CRR Holders must attend a training class at least once prior to participating in the CRR Allocations or CRR Auctions. The CAISO may update training requirements annually or on an as-needed basis. Unless granted a waiver by the CAISO, Candidate CRR Holders and CRR Holders shall at all times have in their employment a person that has attended the CAISO's CRR training class and shall notify the CAISO as soon as practicable of a change in such status.

36.6 [NOT USED]

36.7 Bilateral CRR Transactions.

36.7.1 Transfer of CRRs.

36.7.1.1 General Provisions of CRR Transfers.

A CRR Holder may sell or otherwise transfer CRRs in increments of at least **one-thousandth** of a MW. Sales or other such transfers must be for at least a full day term consistent with the on-peak or off-peak specification of the CRR. The transferee may be any entity that is a Candidate CRR Holder or a CRR Holder consistent with the CAISO Tariff and the applicable Business Practice Manuals. All CRRs that are so sold or otherwise transferred by the CRR Holder continue to be subject to the relevant terms and conditions set forth in the CAISO Tariff and the applicable Business Practice Manuals.

36.7.1.2 Specific Provisions for Transfer of Long Term CRRs.

A CRR Holder that holds Long Term CRRs may sell or transfer through the Secondary Registration System MW portions and temporal segments of a Long Term CRR corresponding to the current calendar year as well as the calendar year covered by the most recently completed annual CRR Allocation. For such sales or transfers the Long Term CRR will be subject to the same limits on granularity that apply to Seasonal CRRs and Monthly CRRs, as specified in Section 36.7.1 of this Appendix. A CRR Holder that holds Long Term CRRs may not transfer or sell through the Secondary Registration System any temporal segment of a Long Term CRR beyond the calendar year covered by the most recently completed annual CRR Allocation. For temporal segments beyond the year covered by the most recently completed annual CRR Allocation, the CRR Holder to whom a Long Term CRR was originally allocated remains the holder

of record of the entire Long Term CRR for CAISO Settlement purposes. Allocated Long Term CRRs represent binding ten-year commitments by a CRR Holder that holds Long Term CRRs and may not be terminated or otherwise modified by the CRR Holder prior to the end of the Long Term CRR's ten-year term.

36.7.2 Responsibility of the CAISO.

The CAISO provides Market Participants a Secondary Registration System to facilitate and track CRR bilateral transactions. The bulletin board of the Secondary Registration System enables any entity that wishes to purchase or sell CRRs to post that information.

36.7.3 CRR Holder Reporting Requirement.

CRR Holders must report to the CAISO by way of the Secondary Registration System all bilateral CRR transactions consistent with the terms of this CAISO Tariff and the Business Practice Manuals. Both the transferor and the transferee of the CRRs must register the transfer of the CRR with the CAISO using the Secondary Registration System at least five (5) Business Days prior to the effective date of transfer of revenues associated with a CRR. The CAISO shall not transfer any Settlement related to any CRR until such time that the CRR transfer has been successfully recorded through the SRS and the transferee has met all the creditworthiness requirements as specified in Section 12 of the CAISO Tariff and Section 12.6 of this Appendix. Both the transferor and transferee shall submit the following information to the Secondary Registration System: (i) the effective start and end dates of the transfer of the CRR; (ii) the identity of the transferor; (iii) the identity of the transferee; (iv) the quantity of CRRs being transferred; (v) the CRR Sources and CRR Sinks of the CRRs being transferred; and (vi) time of use period of the CRR. The transferee must meet all requirements of CRR Holders, including disclosure to the CAISO of all entities with which the transferee is affiliated that are CRR Holders or Market Participants as defined in Section 36.5 of this Appendix.

36.8 CRR Allocation.

The CAISO allocates CRRs to Load Serving Entities serving Load internal to CAISO Control Area, including MSS Operators as described in Section 36.10 of this Appendix, as well as Qualified OCALSEs. All CRRs allocated under the terms of this Section 36.8 will be CRR Obligations.

36.8.1 Structure of the CRR Allocation Process.

The CAISO conducts an annual CRR Allocation: (i) once a year for the entire year for Seasonal CRRs; and (ii) once a year for the ten-year term of Long Term CRRs. The annual CRR Allocation releases Seasonal CRRs and Long Term CRRs for four seasonal periods. The CAISO also conducts monthly CRR Allocations twelve times a year in advance of each month. Within each annual and monthly CRR Allocation process the CAISO performs distinct allocation processes for each on-peak and off-peak time of use specification. The CRR Allocation process for CRR Year One is a distinct process that differs from subsequent CRR Allocations as described in Sections 36.8.3.1 and 36.8.3.2 of this Appendix. Each CRR Allocation procedure is based on nominations to the CAISO by LSEs or Qualified OCALSEs eligible to receive CRRs. The CAISO performs adjustments to the Seasonal and Long Term CRRs allocated to LSEs as necessary to reflect Load Migration between LSEs, as described in Section 36.8.5 of this Appendix. A timeline of the CRR Allocation and CRR Auction processes is contained in the BPMs.

36.8.2 Load Eligible for CRRs and Eligible CRR Sinks.

Any entity that wishes to participate in the CRR Allocation process must provide information that demonstrates that it has an obligation to serve load. An LSE's eligibility for allocation of CRRs is measured by the quantity of Load that it serves that is exposed to Congestion Charges for the use of the CAISO Controlled Grid as determined in Sections 36.8.2.1 and 36.8.2.2 of this Appendix. An OCALSE's eligibility for allocation of CRRs is also measured by the quantity of load that it serves that is exposed to Congestion Charges for the use of the CAISO Controlled Grid as determined in Section 36.9.3 of this Appendix. For LSEs, the information necessary may include, but is not limited to, Settlement Quality Meter Data or relevant documents filed with the California Energy Commission. For OCALSEs, the necessary information may include, but is not limited to, historical tagged Real-Time Interchange Export Schedules and historical load data reflecting the load they serve that is exposed to Congestion Charges for the use of the CAISO Controlled Grid. In addition, each such OCALSE shall support its data submission with a written sworn affidavit by an executive authorized to represent the OCALSE attesting to the accuracy of the data, and the CAISO will have the right to audit the raw data and calculations used to develop the submitted data set. An LSE serving internal Load is eligible for CRRs up to its Seasonal or Monthly CRR Eligible Quantity, which is derived from its Seasonal or Monthly CRR Load Metric as described in Sections 36.8.2.1 and 36.8.2.2 of this Appendix, respectively. Seasonal and Monthly CRR Eligible Quantities for Qualified OCALSEs are determined as provided in Section 36.9.3 of this Appendix. These quantities are calculated for each LSE or Qualified OCALSE separately for each combination of season and time of use period for the annual CRR Allocation process, and for each time of use period for each monthly CRR Allocation process, and for each CRR Sink at which the eligible LSE serves Load or the Qualified OCALSE exports Energy from the CAISO Control Area. MSS eligibility for CRRs will account for net or gross MSS Settlement in accordance with Section 4.9.13.1 of this Appendix. If the MSS Operator elects net Settlement, LSEs for such MSS Load Operator shall submit CRR Sink

nominations at the MSS LAP. If the MSS elects for gross Settlement, LSEs for such MSS Load shall submit CRRs Sink nominations at the applicable Default LAP. Load that is Pumped-Storage Hydro Units but is not Participating Load may be scheduled and settled at a PNode or Custom Load Aggregation Point and therefore LSEs for such Load shall submit CRR Sink nominations at the applicable PNode or Custom Load Aggregation Point. Load that is a Participating Load that is also aggregated is scheduled and settled at a Custom Load Aggregation Point that is customized specifically for such Load and, therefore, LSEs for such Participating Load shall submit CRR Sink nominations at the Custom Load Aggregation Point. Load that is Participating Load is scheduled and settled at an individual PNode, and therefore LSEs for such Load shall submit CRR Sink nominations at the applicable PNode. Load that is non-Participating Load, is not Pumped-Storage Hydro Units, and is not Load associated with ETCs, TORs, or MSS Operators that elect net Settlement, is scheduled and settled at the Default LAP. Therefore, LSEs for such Load shall submit CRR Sink nominations at their assigned Default LAP or Default LAPs if the Load they serve is located in more than one Default LAP. In tier 3 of the annual process and tier 2 of the monthly process, such LSEs may also submit CRR Sink nominations at a Sub-LAP of their assigned Default LAP. The CAISO will make available, prior to the beginning of the CRR Allocation process, a list of allowable CRR Sinks to be used in the allocation.

36.8.2.1 Seasonal CRR Eligible Quantity.

The CAISO constructs load duration curves by season and time of use periods for the annual CRR Allocation process for each LSE based on the LSE's submission to the CAISO of its historical hourly Load data for the prior year, for each LAP within which the LSE serves Load. An LSE's Seasonal CRR Load Metric for each season and time of use period is the MW level of Load that is exceeded only in 0.5% of the hours based on the LSE's historical Load data. In the event that the LSE has lost or gained net Load through Load Migration during the course of the prior year, the historical Load data will be adjusted to reflect the loss or gain in accordance with the applicable BPM. The CAISO calculates an LSE's Seasonal CRR Eligible Quantity by first subtracting from that LSE's Seasonal CRR Load Metric the quantity of Load served by its TORs, ETCs, and Converted Rights to form the LSE's Adjusted Load Metric, and then multiplying the result by 0.75.

36.8.2.2 Monthly CRR Eligible Quantity.

36.8.2.2.1 Based on Load Forecast.

Each month, LSEs whose load forecasts are verifiable in accordance with Section 36.8.6 of this Appendix will submit hourly load forecast data for the relevant month. Each month the CAISO will use the LSE's submitted hourly load forecast data for the relevant month to calculate two load duration curves (one on-peak and one off-peak load duration curve for the applicable month) to form the basis for monthly allocations for each CRR Sink in which the LSE serves Load. Each LSE's submitted hourly forecast data should reflect any Load growth that is not due to Load Migration as well as the effect of net Load Migration for that LSE. The Monthly CRR Load Metric for such Load is the MW level of Load that is exceeded only in 0.5% of the hours based on the LSE's submitted load forecast. The CAISO will calculate an LSE's Monthly CRR Eligible Quantity by subtracting from that LSE's Monthly CRR Load Metric the quantity of Load served by its TORs, ETCs, and Converted Rights. In addition, the CAISO will adjust the LSE's Monthly CRR Eligible Quantity, if such an adjustment is determined to be necessary pursuant to Section 36.8.6 of this Appendix.

36.8.2.2.2 Based on Historical Load Data.

An LSE that serves Load that is eligible for CRRs but for which its load forecast is not verifiable in accordance with Section 36.8.6 of this Appendix shall, each month, submit to the CAISO five (5) years of prior hourly historical load data for that Load for the same applicable month. Such LSE may submit fewer years of historical data for that Load if granted a waiver by the CAISO because five (5) years of such load data does not exist. Each month the CAISO will use the LSE's submitted hourly historical load data for the relevant month to calculate two (2) load duration curves for each year of historical load data (one on-peak and one off-peak load duration curve for the applicable month) for each CRR Sink in which such Load is located. For each load duration curve, the CAISO will calculate the MW level of Load that is exceeded only in 0.5% of the hours. The CAISO will calculate an LSE's Monthly CRR Eligible Quantity for each on-peak and off-peak period for such Load by averaging the 0.5% exceeded values for all years of submitted historical data, and then subtracting the quantity of Load served by its TORs, ETCs, and Converted Rights.

36.8.3 CRR Allocation Process.

36.8.3.1 Annual CRR Allocation for CRR Year One.

The annual CRR Allocation process for CRR Year One consists of a sequence of four (4) tiers for each season and time of use period (on-peak and off-peak). Each tier will feature a SFT applied to the CRR nominations submitted by eligible LSEs or Qualified OCALSEs, the results of which are provided by the CAISO to the respective LSEs or Qualified OCALSEs prior to the LSEs or Qualified OCALSEs submitting their nominations to the next tier. Allocations of CRRs in each tier are considered final once they are provided by the CAISO to the respective LSEs or Qualified OCALSEs. After each tier, LSEs or Qualified OCALSEs will have an amount of time as specified in the Business Practice Manual after their receipt of the results of each tier to submit their nominations for the next tier, if there is one. The annual CRR Allocation allows LSEs or Qualified OCALSEs to submit nominations for Seasonal CRRs up to their Seasonal CRR Eligible Quantities for each season of the relevant year, each time of use CRR Sink as provided in Sections 36.8.3.1.1, 36.8.3.1.2 and 36.8.3.1.4 of this Appendix. The annual CRR Allocation also allows LSEs to submit nominations for Long Term CRRs up to twenty percent (20%) of their Adjusted Load Metric for each season, time of use period and each LAP; except that an LSE that demonstrates that more than twenty percent (20%) of its Adjusted Load Metric is covered by a combination of long-term procurement arrangements of ten (10) years or greater and ownership of generation resources is able to submit nominations for a greater amount as specified in Section 36.8.3.1.3 of this Appendix. As provided in Section 36.8.3.1.3.2 of this Appendix, the annual CRR Allocation allows a Qualified OCALSE to submit nominations for Long Term CRRs up to fifty percent (50%) of its Adjusted Load Metric for each season, time of use period and Scheduling Point provided that the Qualified OCALSE demonstrates that all of its nominated Long Term CRR Sources are covered by a combination of long-term procurement arrangements of ten (10) years or greater and ownership of generation resources. The annual CRR Allocation for CRR Year One will be conducted in the following sequence of tiers:

36.8.3.1.1 Tier 1. In tier 1, an LSE or a Qualified OCALSE may nominate and the CAISO will allocate to the LSE or a Qualified OCALSE Seasonal CRRs up to fifty percent (50%) of its Seasonal CRR Eligible Quantity for each season, time of use period and CRR Sink. An LSE or a Qualified OCALSE can nominate Seasonal CRRs sourced at Trading Hubs in accordance with the LSE's or Qualified OCALSE's verified CRR Sources. In running the SFT the CAISO shall disaggregate the Seasonal CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix. All allocated CRRs that result from such disaggregation will be Point-to-Point CRRs each of whose CRR Source is a Generating Unit PNode that is an element of the Trading Hub.

36.8.3.1.2 Tier 2. In tier 2, an LSE or a Qualified OCALSE may nominate and the CAISO will allocate to the LSEs or Qualified OCALSEs Seasonal CRRs up to seventy-five percent (75%) of its Seasonal CRR Eligible Quantity for each season, time of use period and CRR Sink, minus the quantity of CRRs allocated to that LSE or Qualified OCALSE in tier 1. An LSE or a Qualified OCALSE can nominate Seasonal CRRs sourced at Trading Hubs in accordance with the LSE's or Qualified OCALSE's verified CRR Sources. In tier 2 an LSE or a Qualified OCALSE with a verified Trading Hub CRR Source may nominate up to seventy-five percent (75%) of the Adjusted Verified CRR Source Quantity for that Trading Hub, minus the total MW quantity of Point-to-Point CRRs the LSE or Qualified OCALSE was allocated in tier 1 as a result of its tier 1 nomination of CRRs sourced at that Trading Hub. In running the SFT the CAISO shall disaggregate the Seasonal CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix. All allocated CRRs that result from such disaggregation will be Point-to-Point CRRs each of whose CRR Source is a Generating Unit PNode that is an element of the Trading Hub.

36.8.3.1.3 Tier LT. Tier LT will follow tier 2 for CRR Year One. In Tier LT, an LSE or a Qualified OCALSE may nominate Long Term CRRs from the Seasonal CRRs allocated in tiers 1 and 2 as provided in this Section 36.8.3.1. The cleared Point-to-Point CRRs awarded in tier 1 and tier 2 that resulted from disaggregated CRR nominations sourced at a Trading Hub may not be nominated in Tier LT in CRR Year One. Any Point-to-Point CRRs awarded as a result of disaggregated CRR nominations sourced at a Trading Hub, as described in Section 36.8.4.1 of this Appendix, must be nominated as Trading Hub CRRs as described in this Section 36.8.3.1.3 of this Appendix. In running the SFT the CAISO shall disaggregate the Seasonal CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix. All allocated Long Term CRRs that result from such disaggregation will be Point-to-Point CRRs each of whose CRR Source is a Generating Unit PNode that is an element of the Trading Hub.

36.8.3.1.3.1 Tier LT for LSEs.

The quantity of Seasonal CRRs that an LSE can nominate as Long Term CRRs is limited to twenty percent (20%) of the LSE's Adjusted Load Metric, except that an LSE that can demonstrate that more than twenty percent (20%) of its Adjusted Load Metric is covered by a combination of long-term procurement arrangements of ten (10) years or greater and ownership of generation resources is able to submit nominations for a greater amount as provided in this section. Such demonstrations shall be provided by the requesting LSE to the CAISO through the submission of a written sworn declaration by an executive employee authorized to represent the LSE and attest to the accuracy of the data demonstration. As necessary, the CAISO may request, and such LSE must produce in a timely manner, documents in support of such declaration. If the LSE has demonstrated that more than twenty percent (20%) of its Adjusted Load Metric is covered by a combination of long-term procurement arrangements of ten (10) years or greater and ownership of generation resources, the amount of Long Term CRRs that it may nominate is equal to the minimum of: (i) the sum of the owned resources and

long-term procurement arrangements of ten (10) years or more and (ii) fifty percent (50%) of the LSE's

Adjusted Load Metric. Subject to the maximum quantities described above in this Section 36.8.3.1.3.1,

an LSE can nominate CRRs sourced at a Trading Hub in Tier LT up to the total MW amount of the Point-

to-Point CRRs the LSE was allocated in tiers 1 and 2 as a result of its disaggregated tier 1 and 2

nominations of CRRs sourced at that Trading Hub.

36.8.3.1.3.2 Tier LT for Qualified OCALSEs.

A Qualified OCALSE may submit nominations for Long Term CRRs up to fifty percent (50%) of its

Adjusted Load Metric for each season, time of use period and Scheduling Point. The Qualified OCALSE

must demonstrate that all of its nominated Long Term CRRs are supported by a combination of long-term

procurement arrangements of ten (10) years or greater and ownership of generation resources. Such

demonstrations shall be provided by the requesting Qualified OCALSE to the CAISO through the

submission of a written sworn declaration by an executive employee authorized to represent the Qualified

OCALSE attesting to the accuracy of the data demonstration. As necessary, the CAISO may request,

and such Qualified OCALSE must produce in a timely manner, documents in support of such declaration.

36.8.3.1.3.3 Tier LT SFT.

After receiving nominations for Long Term CRRs from LSEs and Qualified OCALSEs, the CAISO will run SFTs to ensure the feasibility of the nominated Long Term CRRs for the remaining nine years of the ten-year term of the Long Term CRR. The SFT runs in Tier LT will test the feasibility of only the Long Term CRR nominations and will not include in the analysis those Seasonal CRRs allocated in tiers 1 and 2 that are not nominated as Long Term CRRs. The quantity of Long Term CRRs that can be allocated for any season and time of use period must be feasible for the entire ten-year term of the Long Term CRR. As a result of the Tier LT SFT runs, Long Term CRR nominations may not be fully allocated; however, such a result will not affect the CRR Year One validity of the Seasonal CRR allocated in tiers 1 and 2. The CAISO will inform the nominating entity of the results of the Tier LT SFTs before the deadline for submission of the tier 3 nominations.

36.8.3.1.4 Tier 3. In tier 3, an LSE or a Qualified OCALSE may nominate and the CAISO will allocate to the LSE or Qualified OCALSE Seasonal CRRs up to one hundred percent (100%) of its Seasonal CRR Eligible Quantity for each season, minus the quantity of CRRs allocated to that LSE or Qualified OCALSE in tiers 1 and 2. In tier 3, Sub-LAPs will be eligible CRR Sinks provided that the Sub-LAP is within the nominating LSE's Default LAP. An LSE or a Qualified OCALSE can nominate Seasonal CRRs sourced at Trading Hubs. In running the SFT the CAISO shall disaggregate the Seasonal CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix. All allocated CRRs that result from such disaggregation will be Point-to-Point CRRs each of whose CRR Source is a Generating Unit PNode that is an element of the Trading Hub. A Qualified OCALSE can only nominate CRRs from its verified CRR Sources as provided in Section 36.8.3.4 of this Appendix.

36.8.3.2 Monthly CRR Allocation for CRR Year One.

The monthly CRR Allocation in CRR Year One shall consist of a sequence of two (2) tiers for each time of use period (on-peak and off-peak). The monthly CRR Allocation will distribute Monthly CRRs to each LSE or Qualified OCALSE up to one hundred percent (100%) of its Monthly CRR Eligible Quantity, minus CRRs allocated to that LSE or Qualified OCALSE in the annual CRR Allocation for the relevant month and time of use period. The monthly CRR Allocation for CRR Year One will be conducted as follows:

36.8.3.2.1 Tier 1. In tier 1 of the monthly CRR Allocations, an LSE or a Qualified OCALSE may nominate and the CAISO will allocate to the LSE or Qualified OCALSE Monthly CRRs up to fifty percent (50%) of the difference between its Monthly CRR Eligible Quantity and the quantity of Seasonal CRRs and previously allocated Long Term CRRs that apply to that month and time of use period. An LSE or a Qualified OCALSE can nominate Monthly CRRs sourced at Trading Hubs in accordance with the LSE's or Qualified OCALSE's verified CRR Sources. In running the SFT the CAISO shall disaggregate the Monthly CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix. All allocated CRRs that result from such disaggregation will be Point-to-Point CRRs each of whose CRR Source is a Generating Unit PNode that is an element of the Trading Hub.

36.8.3.2.2 Tier 2. In tier 2 of the monthly CRR Allocations, an LSE or a Qualified OCALSE may nominate and the CAISO will allocate to the LSE or Qualified OCALSE Monthly CRRs up to one hundred percent (100%) of the difference between its CRR Eligible Quantity and the quantity of Seasonal CRRs and previously allocated Long Term CRRs that apply to that month and time of use period, minus the quantity of CRRs the entity was allocated in tier 1 of the CRR Year One monthly CRR Allocation. An LSE or a Qualified OCALSE can nominate Monthly CRRs sourced at Trading Hubs. In running the SFT the CAISO shall disaggregate the Monthly CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix. In tier 2 of the monthly CRR Allocation, Sub-LAPs will be eligible CRR Sinks provided that the Sub-LAP is within the nominating LSE's Default LAP. A Qualified OCALSE can only nominate CRRs from its verified CRR Sources as provided in Section 36.8.3.4.2 of this Appendix.

36.8.3.3 [NOT USED]

36.8.3.4 Source Verification.

Source verification is required for LSE CRR nominations in tiers 1 and 2 of the CRR Year One annual allocation process and in tier 1 of each CRR Year One monthly allocation process. Source verification is required for all Qualified OCALSE CRR nominations in all tiers of all CRR Allocation processes.

36.8.3.4.1 CRR Year One Source Verification for LSEs.

In CRR Year One, nominations for tier 1 and tier 2 of the annual CRR Allocation and tier 1 of the monthly CRR Allocations must be source verified for all LSEs. The CAISO will make available, prior to the beginning of the allocation process, a list of allowable CRR Sources to be used in the allocation. An LSE must demonstrate that it could actually submit Bids, including Self-Schedules and Inter-SC Trades, for Energy

from the locations to be nominated as CRR Sources to serve its Load either through ownership of, or contractual rights to receive Energy from, the relevant Generating Units, or a contract to take ownership of power at the relevant source, such as a Trading Hub or a Scheduling Point. *For the second, third and fourth quarters of calendar year 2008 for CRR Year One, in conducting its source verification the CAISO will use data for the period beginning April 1, 2006 and ending December 31, 2006. For the first quarter of calendar year 2009 for CRR Year One, the CAISO will use data for the period beginning January 1, 2007 and ending March 31, 2007 as the basis for verification.* Such demonstrations shall be provided by the requesting LSE to the CAISO through the submission of a written sworn declaration by an executive employee authorized to represent the LSE and attest to the accuracy of the data demonstration. As necessary, the CAISO may request, and such LSE must produce in a timely manner, documents in support of such declaration.

36.8.3.4.2 Source Verification for Qualified OCALSEs.

All CRR nominations by Qualified OCALSEs must be source verified. A Qualified OCALSE's source verification will be based on its legitimate need showing as specified in Section 36.9.1 of this Appendix.

36.8.3.4.3 Calculation of Verified CRR Source Quantity.

The Verified CRR Source Quantity associated with each verified CRR Source for a particular LSE or Qualified OCALSE will be: (i) for an owned generation resource the PMax of the unit multiplied by the LSE's or Qualified OCALSE's ownership share; (ii) for a contract with a generation resource, the hourly MWh of Energy specified in the contract averaged over all hours of the relevant time of use period, but no greater than the PMax of the unit; or (iii) for a contract that delivers Energy to a Trading Hub or Scheduling Point, the hourly MWh of energy specified in the contract for delivery from the supplier to the LSE or Qualified OCALSE at the Trading Hub or Scheduling Point, averaged over all hours of the relevant time of use period. Energy contracts submitted by an LSE to demonstrate that the LSE can submit Bids, including Self-Schedules and Inter-SC Trades, for Energy from the nominated CRR Sources to serve its Load must be at least one month in duration. Energy contracts submitted by a Qualified OCALSE to demonstrate that the Qualified OCALSE can submit Bids, including Self-Schedules and Inter-SC Trades, for Energy from the nominated CRR Sources to serve its Load must be at least one month in duration to support nominations of Monthly and Seasonal CRRs, and at least ten (10) years in duration to support nominations of Long Tem CRRs. Nominations of CRRs for which the CRR Source is a Scheduling Point must be source verified in accordance with Section 36.8.4.2 of this Appendix.

36.8.3.4.4 Calculation of Adjusted Verified CRR Source Quantity.

For nominations by an LSE and a Qualified OCALSE, except for a Qualified OCALSE's nomination of Long Term CRRs, the CAISO will consider a contract that covers a portion of a season (but not less than one month) to be acceptable verification, with the adjustment described below, for the entire season for which a CRR is nominated. The CAISO will also consider a contract not less than one month in duration that covers portions of two consecutive months to be acceptable verification, with the adjustment described below, for both of the months that are partially covered. In such cases, for a contract that covers only a portion of the season or month for which the

LSE or Qualified OCALSE wishes to nominate source-verified CRRs, the CAISO will calculate an

Adjusted Verified CRR Source Quantity, which equals the Verified CRR Source Quantity times the ratio of the number of days covered by the contract for a particular month or season to the total number of days in that month or season, consistent with the time of use period of the CRRs being nominated. **Contracts submitted by a Qualified OCALSE to support nomination of Long Term CRRs must be at least ten (10) years in duration and cover the entire season of the Long Term CRR being nominated, and therefore the Adjusted Verified CRR Source Quantity calculation does not apply to such nominations.**

36.8.3.5 Annual CRR Allocation Beyond CRR Year One.

The annual CRR Allocation for years beyond CRR Year One consists of a sequence of four (4) tiers for each season and time of use period (on-peak and off-peak). Allocations of CRRs in each tier are considered final once they are provided by the CAISO to the respective LSEs or Qualified OCALSEs. After each tier, LSEs or Qualified OCALSEs will have an amount of time as specified in the Business Practice Manual after their receipt of the results of each tier to submit their nominations for the next tier, if there is one. The annual CRR Allocation will allow LSEs or Qualified OCALSEs to submit nominations up to their Seasonal CRR Eligible Quantities minus the quantity of previously allocated Long Term CRRs for each season of the relevant year, each time of use period and each CRR Sink at which they serve Load. Annual CRR Allocations for years beyond CRR Year One will be conducted in the following sequence of tiers:

36.8.3.5.1 Tier 1 – Priority Nomination Process.

Tier 1 of the annual CRR Allocation in years beyond CRR Year One will be a Priority Nomination Process through which CRR Holders may nominate some of the same CRRs that they were allocated in the immediately previous year **annual CRR Allocation process**. **As provided in Section 36.8.3.4.2 of this Appendix, nominations by a Qualified OCALSE in the PNP are subject to source verification.** In all annual CRR Allocations after CRR Year One, an LSE or a Qualified OCALSE may make PNP nominations up to the lesser of: (1) two-thirds of its Seasonal CRR Eligible Quantity, minus the quantity of previously allocated Long Term CRRs for each season, time of use period and CRR Sink for that year; or, (2) the total quantity

of Seasonal CRRs allocated to that LSE in the previous annual CRR Allocation, minus the quantity of previously allocated Long Term CRRs for each season, time of use period and CRR Sink, and minus any reduction for net loss of Load or plus any increase for net gain of Load through retail Load Migration as described in Section 36.8.5.1 of this Appendix. In addition, an LSE's or Qualified OCALSE's nomination of any particular CRR Source-Sink combination in the PNP may not exceed the MW quantity of CRRs having that CRR Source and CRR Sink that the LSE or Qualified OCALSE was allocated in the previous annual CRR Allocation for the same season and time of use period, and in the case of an LSE, adjusted for net Load loss or gain resulting from Load Migration as described in Section 36.8.5.2.2 of this Appendix. An LSE or a Qualified OCALSE may not nominate CRRs sourced at Trading Hubs in the PNP. CRRs whose CRR Sink is a Sub-LAP are not eligible for nomination in the PNP. A CRR whose CRR Sink is a Custom LAP or PNode is eligible for nomination in the PNP. PNP Eligible Quantities are not affected by secondary transfers of CRRs, except as performed by the CAISO to reflect Load Migration as described in Section 36.8.5 of this Appendix. That is, with the exception of transfers to reflect Load Migration: (i) an LSE or a Qualified OCALSE may nominate in the PNP a CRR it was allocated in the prior annual CRR Allocation even though it transferred that CRR to another party during the year, and (ii) an LSE or a Qualified OCALSE may not nominate in the PNP a CRR that it received through a secondary transfer from another party. CRRs received through a CRR Auction are not eligible for nomination in the PNP. CRRs received as Offsetting CRRs to reflect Load Migration are not eligible for nomination in the PNP. The maximum quantity of CRRs that an LSE or a Qualified OCALSE may nominate in the PNP is fifty percent (50%) of its Adjusted Load Metric, minus any previously allocated Long Term CRRs that are valid for the term of the CRRs being nominated. The CAISO does not guarantee that all CRR nominations in the PNP will be allocated. The CAISO will conduct an SFT to determine whether all CRR nominations in the PNP are simultaneously feasible. If the SFT determines that all priority nominations are not simultaneously feasible, the CAISO will reduce the allocated CRRs until simultaneous feasibility is achieved.

36.8.3.5.2 Tier LT.

In years subsequent to CRR Year One, Long Term CRRs will be allocated as provided in this section.

36.8.3.5.2.1 Tier LT for LSEs.

In Tier LT of CRR Year Two, an LSE may nominate Long Term CRRs from any of the Seasonal CRRs it was allocated in the PNP up to a maximum of thirty percent (30%) of its Adjusted Load Metric, minus the quantity of previously allocated Long Term CRRs that are valid for that year; except that the LSE may nominate Long Term CRRs in amounts greater than thirty percent (30%) but no more than fifty percent (50%) of its Adjusted Load Metric if the LSE demonstrates that more than thirty percent (30%) of its Adjusted Load Metric is covered by a combination of long-term procurement arrangements of ten (10) years or greater and ownership of generation resources. Such demonstrations shall be provided by the requesting LSE to the CAISO through the submission of a written sworn declaration by an executive employee authorized to represent the LSE and attest to the accuracy of the data demonstration. As necessary, the CAISO may request, and such LSE must produce in a timely manner, documents in support of such declaration. If the LSE has demonstrated that more than thirty percent (30%) of its Adjusted Load Metric is covered by a combination of long-term procurement arrangements of ten (10) years or greater and ownership of generation resources, the amount of Long Term CRRs that it may nominate is equal to the minimum of: (i) the sum of the owned resources and long-term procurement arrangements of ten (10) years or more, minus the quantity of previously allocated Long Term CRRs that are valid for that CRR year, and (ii) fifty percent (50%) of the LSE's Adjusted Load Metric, minus the quantity of previously allocated Long Term CRRs that are valid for that CRR year. In CRR Year Three, the limit on Long Term CRR nominations will increase by ten percent (10%) to forty percent (40%) of the eligible entity's Adjusted Load Metric but shall not exceed fifty percent (50%) of the Adjusted Load Metric. In CRR Year Three, an LSE may exceed the

forty percent (40%) limit on Long Term CRR nominations if it demonstrates that its Adjusted Load Metric is covered by a combination of long-term procurement arrangements of ten (10) years or greater and ownership of generation resources. The amount of Long Term CRRs that it may nominate is equal to the minimum of: (i) the sum of the owned resources and long-term procurement arrangements of ten (10) years or more, minus the quantity of previously allocated Long Term CRRs that are valid for that CRR year, and (ii) fifty percent (50%) of the LSE's Adjusted Load Metric, minus the quantity of previously allocated Long Term CRRs that are valid for that CRR year. In CRR Year Four and all subsequent years, an LSE may nominate Long Term CRRs from any of the Seasonal CRRs allocated in the PNP up to the maximum of fifty percent (50%) of its Adjusted Load Metric, minus the quantity of previously allocated Long Term CRRs that are valid for that year.

36.8.3.5.2.2 Tier LT for Qualified OCALSEs.

A Qualified OCALSE may submit nominations for Long Term CRRs up to the portion of its Adjusted Load Metric for which it has demonstrated coverage by a combination of long-term procurement arrangements of ten (10) years or greater and ownership of generation resources, up to a maximum of fifty percent (50%) of its Adjusted Load Metric for each season, time of use period and Scheduling Point, minus the quantity of previously allocated Long Term CRRs that are valid for that CRR year. Such demonstrations shall be provided by the requesting Qualified OCALSE to the CAISO through the submission of a written sworn declaration by an executive employee authorized to represent the Qualified OCALSE and attest to the accuracy of the data demonstration. As necessary, the CAISO may request, and such Qualified OCALSE must produce in a timely manner, documents in support of such declaration. Contracts submitted in support of OCALSE nominations of Long Term CRRs must cover the entire season of the Long Term CRR being nominated.

36.8.3.5.2.3 Tier LT SFT.

After receiving nominations for Long Term CRRs, the CAISO will run SFTs to ensure the feasibility of the nominated Long Term CRRs for the remaining nine years of the ten (10) year term of the Long Term CRR. The SFT run in Tier LT will test the feasibility of only the Long Term CRR nominations and will not include in the analysis those Seasonal CRRs allocated in the PNP that were not nominated as Long Term CRRs. The quantity of Long Term CRRs that can be allocated for any season and time of use period must be feasible for the entire ten (10) year term of the Long Term CRR. As a result of the Tier LT SFT runs, Long Term CRR nominations may not be fully allocated; however, such a result will not affect the validity of: (i) the Long Term CRRs allocated in previous years, or (ii) the Seasonal CRRs allocated in the PNP. The CAISO will inform nominating eligible entities of the results of the Tier LT SFTs before the deadline for submission of the tier 2 nominations.

36.8.3.5.3 Tier 2. In tier 2 of the annual CRR Allocation, the CAISO will allocate Seasonal CRRs to each LSE and Qualified OCALSE up to two-thirds of its Seasonal CRR Eligible Quantity for each season, time of use period and CRR Sink, minus the quantity of: (i) CRRs allocated to that LSE or Qualified OCALSE in tier 1, and (ii) Long Term CRRs previously allocated to it that are valid for the CRR term currently being allocated. An LSE or a Qualified OCALSE can nominate Seasonal CRRs sourced at Trading Hubs. In running the SFT the CAISO shall disaggregate the Seasonal CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix.

36.8.3.5.4 Tier 3. In tier 3 of the annual CRR Allocation, the CAISO will allocate Seasonal CRRs to each LSE or Qualified OCALSE up to one hundred percent (100%) of its Seasonal CRR Eligible Quantity for each season, time of use period and CRR Sink, minus the quantity of: (i) CRRs allocated to that LSE or Qualified OCALSE in tiers 1 and 2, and (ii) Long Term CRRs previously allocated to that eligible entity that are valid for the CRR

term currently being allocated. In tier 3 of the annual CRR Allocation, Sub-LAPs will be eligible CRR Sinks provided that the Sub-LAP is within the nominating LSE's Default LAP. An LSE or a Qualified OCALSE can nominate Seasonal CRRs where the CRR Source is a Trading Hub. In running the SFT the CAISO shall disaggregate the Seasonal CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix.

36.8.3.5.5 Alternatives for Renewal of Long Term CRRs and for the Transition of Expiring ETCs and Converted Rights to Long Term CRRs.

Eligible entities may, in the final year of a Long Term CRR, nominate the identical CRR Source, CRR Sink, and MW terms of the expiring Long Term CRR in the PNP conducted that year, subject to any applicable quantity limitations specified in this Section 36. An eligible entity with an Existing Transmission Contract or Converted Rights that expire by the start of the year for which the CRR Allocation process is conducted may participate in the PNP as if its Existing Transmission Contract or Converted Rights sources and sinks were previously allocated Seasonal CRRs, subject to any applicable quantity limitations specified in this Section 36. In either case, if Seasonal CRRs are awarded to an LSE or Qualified OCALSE in the PNP based on its nomination of its expiring rights, such entity may then nominate those Seasonal CRRs in Tier LT of the same year's annual CRR Allocation process, subject to any applicable quantity limitations specified in this Section 36. Alternatively, CRR Holders of expiring LT CRRs, expiring Existing Transmission Contracts or expiring Converted Rights may bypass the tier 1 Priority Nomination Process and nominate their expiring rights as Long Term CRRs in Tier LT one year prior to the year of expiration, subject to any applicable quantity limitations specified in this Section 36. This alternative allows the holder of the expiring rights to nominate Long Term CRRs in the first Tier LT SFT in which the capacity corresponding to the expiring rights becomes available for the full nine year period of the Tier LT SFT. For any entity who elects this alternative and obtains an allocated Long Term CRR, the length of the renewed Long Term CRR (or initial Long Term CRR in the case of expiring Existing Transmission Contracts or expiring Converted Rights) will be nine years, corresponding to the years included in the Tier LT SFT.

36.8.3.6 Monthly CRR Allocation Beyond CRR Year One.

The monthly CRR Allocation shall consist of a sequence of two (2) tiers of allocations for each time of use period (on-peak and off-peak). The monthly CRR Allocation will distribute Monthly CRRs and will allow an LSE and a Qualified OCALSE to nominate CRRs up to one hundred percent (100%) of its Monthly CRR Eligible Quantity, minus the total of any Seasonal CRRs allocated in the annual CRR Allocation, and minus any holdings of Long Term CRRs that are valid for the month and time of use of the CRRs being nominated. All CRR nominations by Qualified OCALSEs must be source verified.

36.8.3.6.1 Tier 1. In tier 1 of the monthly CRR Allocations, each LSE or Qualified OCALSE may nominate Monthly CRRs up to fifty percent (50%) of the difference between its Monthly CRR Eligible Quantity and the total of any Seasonal CRRs allocated in the annual CRR Allocation and any holdings of Long Term CRRs that are valid for the month and time of use of the CRRs being nominated. An LSE or a Qualified OCALSE can nominate Monthly CRRs where the CRR Source is a Trading Hub. In running the SFT the CAISO shall disaggregate the Monthly CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix.

36.8.3.6.2 Tier 2. In tier 2 of the monthly CRR Allocations, each LSE or Qualified OCALSE may nominate Monthly CRRs up to one hundred percent (100%) the difference between its Monthly CRR Eligible Quantity and the total of any Seasonal CRRs allocated in the annual CRR Allocation and any holdings of Long Term CRRs that are valid for the month and time of use of the CRRs being nominated, minus the quantity of CRRs allocated to that LSE or Qualified OCALSE in tier 1 of the current monthly CRR Allocation. In tier 2 of the monthly CRR Allocation, Sub-LAPs will be eligible CRR Sinks, provided that the Sub-LAP is within the nominating LSE's Default LAP. An LSE or a Qualified OCALSE can nominate Monthly CRRs sourced at Trading Hubs. In running the SFT the CAISO shall disaggregate the Monthly CRR nominations sourced at Trading Hubs as described in Section 36.8.4.1 of this Appendix.

36.8.4 Eligible Sources for CRR Allocation.

In the CRR Allocation processes for Seasonal CRRs, Monthly CRRs, and Long Term CRRs, nominated CRR Sources can be either PNodes (including Scheduling Points) or Trading Hubs. An LSE or a Qualified OCALSE may nominate up to one hundred percent (100%) of its Adjusted Verified CRR Source Quantities for Seasonal or Monthly CRRs in the combined tiers of the annual and monthly CRR Allocation processes as provided in this Section. For tiers 1 and 2 of the annual CRR Allocation in CRR Year One, an LSE may nominate CRRs from each of its verified CRR Sources in a quantity no greater than seventy-five percent (75%) of the Adjusted Verified CRR Source Quantity corresponding to each verified CRR Source. The LSE may then use tier 1 of the monthly CRR Allocations in CRR Year One to nominate up to the full one hundred percent (100%) of the Adjusted Verified CRR Source Quantity corresponding to each verified CRR Source. In tiers 1, 2 and 3 of the annual CRR Allocation in each year in which it participates, a Qualified OCALSE may nominate CRRs from each of its verified CRR Sources in a quantity no greater than seventy-five percent (75%) of the Adjusted Verified CRR Source Quantity corresponding to each CRR Source. The Qualified OCALSE may then use tiers 1 and 2 of the monthly CRR Allocations in the same year to nominate up to the full one hundred percent (100%) of the Adjusted Verified CRR Source Quantity corresponding to each verified CRR Source.

36.8.4.1 CRRs with Trading Hub Sources.

For purposes of the CRR Allocation processes the CAISO shall disaggregate CRR nominations with Trading Hub CRR Sources into Point-to-Point CRR nominations each of whose CRR Source is a Generating Unit PNode that is an element of the Trading Hub. In performing this disaggregation the MW quantity of each Point-to-Point CRR nomination will equal the MW quantity of the CRR nomination multiplied by the weighting factor of the corresponding Generating Unit PNode in the defined Trading Hub. The disaggregated, individual Point-to-Point CRRs will be used by the CAISO in conducting the SFTs for the nominated CRRs. In CRR years other than CRR Year One, an LSE may nominate in the PNP any Point-to-Point CRRs it was allocated the previous year as a result of Seasonal CRR nominations with Trading Hubs as CRR Sources, and may then nominate those Seasonal CRRs awarded in the PNP as Long Term CRRs in Tier LT. In CRR Year One, an LSE that was allocated individual Point-to-Point CRRs in tiers 1 and 2 as a result of nominating CRRs sourced at a Trading Hub must nominate CRRs sourced at Trading Hubs in Tier LT in accordance with Section 36.8.3.1.3.1 of this Appendix. For Qualified OCALSEs, all nominated CRR Sources must be source verified as specified in Section 36.9.1 of this Appendix. Any Long Term CRRs allocated by the CAISO as a result of nominations of CRRs sourced at Trading Hubs will be Point-to-Point CRRs each of whose CRR Sources is a Generating Unit PNode that is an element of the Trading Hub.

36.8.4.2 Import CRRs.

An LSE or a Qualified OCALSE may nominate Seasonal, Monthly or Long Term CRRs whose CRR Source is a Scheduling Point in the annual and monthly CRR Allocation in accordance with this Section.

36.8.4.2.1 Scheduling Points as CRR Sources for LSEs in CRR Year One.

In CRR Year One, in tiers 1 and 2 of the annual CRR Allocation process an LSE may nominate Seasonal CRRs whose CRR Source is a Scheduling Point to the extent that it can demonstrate to the CAISO that, for the verification period stated in Section 36.8.3.4 of this Appendix, it owned or was a party to a contract with a System Resource, and that it or the counter-party to the contract had procured appropriate transmission from the applicable transmission provider outside the CAISO to the Scheduling Point. In addition, also in tiers 1 and 2 of the annual CRR Allocation in CRR Year One, all LSEs eligible to nominate CRRs under this Section 36.8 may nominate as CRR Sources, without any verification, shares of the residual import CRR capacity at each Scheduling Point that remains after the completion of the CRR Source verification process. Each LSE's share of the residual import CRR capacity will be calculated as follows. Starting with the total capacity at each Scheduling Point that is available in the DC FNM for the annual CRR Allocation and Auction process, the CAISO will calculate the residual amount of capacity that remains at each Scheduling Point after subtracting the capacity accounted for by those Scheduling Point CRR Sources submitted by LSEs for verification that have been verified. The CAISO will then set aside fifty percent (50%) of this residual amount at each Scheduling Point for the annual CRR Auction, and will allow LSEs to nominate pro rata shares of the other fifty percent (50%) in proportion to their Seasonal CRR Eligible Quantities. In each monthly CRR Allocation during CRR Year One, CRR Source verification will be required in tier 1 as in the annual CRR Allocation process. Following the verification process, the CAISO will calculate and set aside for the

monthly CRR Auction fifty percent (50%) of the import capacity that remains at each Scheduling Point after accounting for the verified Scheduling Point CRR Source submissions to the monthly process and the annual CRR Allocation and Auction results for that month, and will allow LSEs to nominate in tier 1 Monthly CRRs with CRR Sources at each Scheduling Point in quantities up to their pro rata shares of the other fifty percent (50%) in proportion to their Monthly CRR Eligible Quantities.

36.8.4.2.2 Scheduling Points as CRR Sources for LSEs Beyond CRR Year One.

In the annual CRR Allocation processes subsequent to CRR Year One, there will be no special provisions regarding CRR Sources at Scheduling Points in tiers 1 and 2 for LSEs. For tier 3 the CAISO will calculate and set aside for the annual CRR Auction fifty percent (50%) of the import capacity at each Scheduling Point that remains after the tier 1 and tier 2 CRR Allocations and after considering any previously allocated Long Term CRRs that are valid for that month as described in Section 36.4.1 of this Appendix.

In the monthly CRR Allocation processes subsequent to CRR Year One there will be no special provisions regarding CRR Sources at Scheduling Points in tier 1 for LSEs. For tier 2 the CAISO will calculate and set aside for the monthly CRR Auction fifty percent (50%) of the import capacity that remains at each Scheduling Point after accounting for the annual CRR Allocation and Auction results for that month, any previously allocated Long Term CRRs that are valid for that month, and the results of tier 1 of the monthly CRR Allocation.

36.8.4.2.3 Scheduling Points as CRR Sources for Qualified OCALSEs.

In the annual CRR Allocation process a Qualified OCALSE may nominate CRRs whose CRR Source is a Scheduling Point to the extent it meets the requirements of Section 36.9.1 of this Appendix.

36.8.5 Load Migration Between LSEs.

The CAISO shall track Load Migration between LSEs through Load Migration data provided to the CAISO by each UDC, MSS Operator or other entity that provides distribution service to customers. Load Migration will be reflected in the hourly Load data and load forecasts used by the CAISO to calculate the CRR Load Metrics and Seasonal and Monthly CRR Eligible Quantities for each LSE, in accordance with procedures set forth in the applicable Business Practice Manual. Load Migration will be reflected in appropriate adjustments to each affected LSE's Seasonal and Monthly CRR Eligible Quantities in subsequent annual and monthly CRR Allocations, as well as its PNP Eligible Quantities in the next annual CRR Allocation. LSEs that hold Seasonal CRRs or Long Term CRRs and that lose or gain Load through Load Migration must comply with Section 36.8.5.3 of this Appendix regarding the transfers of current CRR holdings to reflect Load Migration.

36.8.5.1 Tracking of Load Migration by CAISO.

The CAISO will implement all appropriate adjustments due to Load Migration on a monthly basis. In order to enable the CAISO to track Load Migration and determine the appropriate adjustments, each UDC, MSS Operator, and other entity that provides distribution service to customers will provide to the CAISO the following minimum information on each customer that migrates between LSEs: (i) customer identification information, (ii) information to establish the customer's retail customer class, (iii) the original and new LSEs serving the customer, (iv) the effective date of the Load Migration, and (v) the most recent twelve (12) months of billing data for the customer. Each UDC, MSS Operator and other entity that provides distribution service to customers will also provide to the CAISO the number of customers served by each LSE in each retail customer class as of the start of each month, plus information on the average consumption by customers in each retail customer class. Further details regarding the information to be supplied to the CAISO is set forth in the applicable Business Practice Manual. The CAISO will receive information from each UDC, MSS Operator, and other entity providing distribution service on an ongoing daily basis, and will perform the calculations for any appropriate adjustments due to Load Migration on a monthly basis. New CRRs allocated due to Load Migration in accordance with Section 36.8.5.3 of this Appendix will be made effective on the first day of the first month, following the CAISO's performance of the calculations, in which the Load Migration is effective by the first of the month.

36.8.5.2 Adjustments to CRR Eligible Quantities to Reflect Load Migration.

An LSE who loses or gains net Load through Load Migration in a given year will have its Seasonal CRR Eligible Quantities in the next annual CRR Allocation reduced or increased, respectively, in proportion to the net Load lost or gained through Load Migration. In addition, an LSE that loses Load through Load Migration in a given year will have its PNP Eligible Quantities reduced in proportion to the amount of Load lost through Load Migration. An LSE that gains Load through Load Migration in a given year will have its PNP Eligible Quantities increased in proportion to the amount of Load gained through Load Migration.

36.8.5.3 Adjustments to Current CRR Holdings to Reflect Load Migration.

Because in between CRR Allocations each LSE can both lose Load and gain Load between itself and multiple other LSEs, the CAISO will calculate and perform appropriate adjustments to current CRR holdings for each pair of LSEs affected by Load Migration to reflect the net amount of Load that migrated between those two LSEs during each Load Migration tracking period and for each LAP in which the LSEs serve Load. The CAISO will perform such calculations in accordance with the appropriate Business Practice Manual, and will perform the adjustments by creating and allocating equal and opposite sets of new CRRs for each pair of LSEs affected by Load Migration. The net Load gaining LSE of the pair will receive a set of new CRRs that match the CRR Sources and CRR Sinks of all the Seasonal and Long Term CRRs previously allocated to the net Load losing LSE of the pair, in MW quantities proportional to the net amount of the net Load losing LSE's Load that migrated to the net Load gaining LSE of the pair within each LAP in which the LSEs serve Load. The net Load losing LSE of the pair will receive a set of new Offsetting CRRs. After the assignment of Offsetting CRRs, the net Load losing LSE will still hold the CRRs it held before it was assigned the Offsetting CRRs. The Load gaining LSE may nominate its new Seasonal CRRs in the Priority Nomination Process of the next annual CRR Allocation process. The net Load losing LSE may not nominate in the Priority Nomination Process either: (i) the Seasonal CRRs corresponding to the new CRRs allocated to the Load gaining LSE, or (ii) the Offsetting CRRs allocated due to Load Migration. An LSE to which the CAISO allocates new CRRs to reflect Load Migration must be either a Candidate CRR Holder or a CRR Holder and meet all requirements applicable to such entities.

36.8.5.4 Load Migration and Compliance with CAISO Credit Requirements.

To the extent that the credit requirements of an LSE as specified in Section 12 are updated by the allocation of new CRRs to reflect Load Migration, the CAISO will do the following. For new CRRs that result in net charges to the affected LSE over a Settlement period these charges will appear on the LSE's Settlement Statement irrespective whether the LSE has met the updated credit requirement. For new CRRs that result in net payments to the affected LSE over a Settlement period and that LSE has not met the updated credit requirements affected by the allocation of new CRRs to reflect Load Migration, the CAISO shall withhold payment until those updated credit requirements are met. At the end of each Settlement period, if the LSE has not met the updated credit requirements resulting from Load Migration CRR transfers, the CAISO will add any net payments that accrued to the transferred CRRs to the CRR Balancing Account to be included in the end-of-month clearing of the CRR Balancing Account, and those net payments will no longer be recoverable by the LSE. The CAISO may place new allocated CRRs into CRR Auctions if the non-compliance with credit or applicable Financial Security requirements is persistent.

36.8.5.5 Load Migration Adjustment for CRR Year One.

For the CRR Year One CRR Allocation process, the CAISO will account for the cumulative Load Migration that takes place between the beginning of the CRR Year One CRR Allocation process and the first date that the Day-Ahead Market is operational as a single adjustment as described in the Business Practice Manuals.

36.8.5.6 Load Migration Reflected in the Monthly CRR Allocation Process.

An LSE who loses or gains net Load through Load Migration must reflect that loss or gain in the monthly Load forecasts it submits to the CAISO for determining its monthly CRR Eligible Quantities for future monthly CRR Allocations.

36.8.6 Load Forecasts Used to Calculate CRR MW Eligibility.

The CAISO will work closely with appropriate state and Local Regulatory Authorities and agencies to ensure that historical Load data and load forecasts used to establish Seasonal and Monthly CRR Eligible Quantities *as provided in Section 36.8.2 of this Appendix* are consistent with the *Load* data and *load* forecasts used to establish resource adequacy requirements.

36.8.7 Long Term CRRs and Participating TO Withdrawals from the CAISO Controlled Grid.

In the event a Participating TO gives the required notice and withdraws facilities or Entitlements from the CAISO Controlled Grid, the CAISO will reconfigure Long Term CRRs as necessary to reflect the CAISO Controlled Grid after the withdrawal. After reconfiguration, the CAISO will run SFTs on the reconfigured Long Term CRRs and, if necessary, reduce some of the reconfigured Long Term CRRs to ensure their feasibility. If the CRR Source and CRR Sink for an allocated Long Term CRR both are located within a departing Participating TO Service Territory, the Long Term CRR would expire on the effective date of the Participating TO's withdrawal.

36.9 CRR Allocation to OCALSEs.

OCALSEs who wish to nominate and be allocated CRR Obligations in the same annual and monthly CRR Allocation processes described in Section 36.8 of this Appendix may do so subject to the provisions of this Section 36.9 of this Appendix and if such OCALSEs are qualified and registered as Candidate CRR Holders or CRR Holders. An OCALSE may participate in the CRR Allocation processes and be allocated CRRs to the extent that: (1) such OCALSE makes a showing of legitimate need for the CRRs nominated as provided by Section 36.9.1 of this Appendix; (2) such OCALSE pre-pays or commits to pay the appropriate Wheeling Access Charge in the amount of MW of CRRs nominated as provided in Section 36.9.2 of this Appendix; (3) the external load for which CRRs are nominated will be exposed to CAISO Congestion charges because it is not served by Supply resources other than exports from the CAISO Control Area; (4) the external load for which CRRs are nominated is not served through an ETC, TOR or Converted Rights by which it has been designated as eligible to receive the reversal of Congestion charges; (5) such OCALSE complies with the verification requirements in Section 36.9.4 of this Appendix; and (6) the nominated CRRs clear the relevant SFTs. An OCALSE that participates in the CRR Allocation processes will be subject to the applicable rules governing the tiered structure of these processes. All CRRs allocated under the terms of this Section 36.9 will be CRR Obligations.

36.9.1 Showing of Legitimate Need.

An OCALSE must make a showing to the CAISO of legitimate need to enable the CAISO to verify the CRR Sources it wants to nominate. All CRR nominations by OCALSEs in all CRR years must be source verified based on the showing of legitimate need. The CAISO's verification of legitimate need will be based on demonstration by the OCALSE of an executed Energy contract from a Generating Unit or System Resource that covers the time period of the CRRs nominated, or ownership of such Generating Unit or System Resource. For such CRR Sources the showing of legitimate need must be made for each CRR term for which the OCALSE wants to nominate CRRs in a timely manner prior to the start of the relevant annual or monthly CRR

Allocation process. For CRR Sources that will be verified based on generating resources located outside the CAISO Control Area, a Scheduling Point must be nominated as the corresponding CRR Source. Generating resources located outside of the CAISO Control Area to be used by the OCALSE to verify a Scheduling Point as a CRR Source must not be located within the OCALSE's own Control Area. The Verified CRR Source Quantity and Adjusted Verified CRR Source Quantity corresponding to any CRR Source nominated by an OCALSE will be calculated in accordance with Section 36.8.3.4 of this Appendix, with the modification that for an OCALSE these quantities will be calculated for each CRR Allocation process in which the Qualified OCALSE wants to participate, consistent with the requirement for ongoing source verification based on a forward showing in conjunction with the OCALSE's annual showing of legitimate need. For a CRR Source that is a Scheduling Point, pursuant to the legitimate need showing requirement, an OCALSE must demonstrate that it has procured the appropriate transmission service from the transmission provider outside the CAISO Control Area to the Scheduling Point that the OCALSE intends to nominate as a CRR Source for the term of the CRR being nominated. Such demonstrations shall be provided by the OCALSE to the CAISO through the submission of a written sworn declaration by an executive employee authorized to represent the OCALSE and attest to the accuracy of the data demonstration. As necessary, the CAISO may request, and such OCALSE must produce in a timely manner, documents in support of such declaration.

36.9.2 Prepayment of Wheeling Access Charges.

36.9.2.1 Prepayment of Wheeling Access Charges for Allocated CRRs.

An OCALSE will be required to prepay relevant Wheeling Access Charges, to be calculated as described in this section and further specified in the Business Practice Manual, for the full term of the Monthly, Seasonal and Long Term CRRs it intends to nominate in order to participate in the CRR Allocation processes and be allocated CRRs. To be eligible for the allocation of Seasonal CRRs or Monthly CRRs the OCALSE must submit the full required prepayment and have it accepted by the CAISO prior to the OCALSE's submission of nominations for the relevant annual or monthly CRR Allocation, except as provided below in Section 36.9.2.2 of this Appendix. To be eligible for nominations of Long Term CRRs,

the OCALSE must submit the full prepayment and have it accepted by the CAISO prior to the OCALSE's submission of nominations of Long Term CRRs in Tier LT, except as provided below in Section 36.9.2.2 of this Appendix. For each MW of Monthly, Seasonal or Long Term CRR to be nominated the nominating OCALSE must prepay one MW of the relevant Wheeling Access Charge, which equals the per-MWh WAC that is associated with the Scheduling Point the OCALSE intends to nominate as a CRR Sink and that is expected at the time the CRR Allocation process is conducted to be applicable for the period of the CRR nominated, times the number of hours comprising the period of the CRR nominated as further specified in the applicable Business Practice Manual.

36.9.2.2 Eligibility for Prepayment of WAC on an Annual or Monthly Basis.

An OCALSE deemed creditworthy pursuant to the requirements of Section 12 may elect to prepay the determined WAC responsibility on a monthly basis for the Seasonal or Long Term CRRs that it seeks to be allocated, provided that such OCALSE has demonstrated a commitment to pay the required WAC for the entire term of the CRRs sought by submitting to the CAISO a written sworn statement by an executive that can bind the entity. In order to be eligible for this option, the OCALSE must submit and the CAISO must accept this sworn statement prior to the applicable CRR Allocation process in which the OCALSE intends to nominate a CRR. An OCALSE choosing to pay on a monthly basis shall make its monthly payments on a schedule specified in the applicable Business Practice Manual. An OCALSE deemed creditworthy pursuant to the requirements of Section 12 may also elect to prepay its determined WAC responsibility associated with an allocated Long Term CRR on an annual basis, provided that such OCALSE has demonstrated a commitment to pay for the entire term of the Long Term CRRs sought by submitting to the CAISO and the CAISO accepting a written sworn statement by an executive that can bind the entity. An OCALSE choosing to pay such WAC obligation on an annual basis shall make its payment each year on a schedule specified in the applicable Business Practice Manual.

36.9.2.3 Refund of Prepaid WAC for Unallocated CRRs.

To the extent that an OCALSE prepays a quantity of the WAC and is not allocated the full amount of CRRs nominated, WAC prepayment for CRRs not allocated will be refunded by the CAISO within thirty (30) days following the completion of the relevant CRR Allocation process.

36.9.3 CRR Eligible Quantities.

The CAISO will calculate the Seasonal and Monthly CRR Eligible Quantities for OCALSEs as described in Section 36.8.2 of this Appendix with the following modifications. The OCALSE must submit two sets of hourly data from which the CAISO will construct load duration curves for determining the Seasonal and Monthly CRR Eligible Quantities. One set of hourly data must reflect the OCALSE's historical hourly exports at the Scheduling Point that is the CRR Sink of the nominated CRRs. The historical hourly exports shall be based on the tagged Real-Time Interchange Export Schedules for the OCALSE. An OCALSE that wishes to nominate multiple Scheduling Points as CRR Sinks in the CRR Allocation process will have distinct CRR Eligible Quantities for each nominated Scheduling Point, and prior to each annual CRR Allocation process must submit historical hourly export data at each such Scheduling Point from which the CAISO will calculate the associated CRR Eligible Quantities. The second set of hourly data must reflect the prior year's hourly metered load for the end-use customers the OCALSE served outside the CAISO Control Area and that were not served from sources other than exports from the CAISO Control Area. The OCALSE's Seasonal and Monthly CRR Eligible Quantities will be based on the lesser of (1) the total historical hourly export data for all Scheduling Points submitted as CRR Sinks, and (2) the hourly metered load for the external end-use customers served by the OCALSE and that were not served from sources other than exports from the CAISO Control Area. An OCALSE also must demonstrate that it has firm transmission rights pursuant to the tariffs of intervening transmission providers from its Scheduling Point sink to the end-use customers in the OCALSE's Control Area. The OCALSE shall support its data submission and the demonstration of transmission rights to its end-use customers with a sworn affidavit by an executive employee authorized to represent the OCALSE and attest to the accuracy of the data and demonstration. As necessary, the CAISO may request, and such OCALSE must produce in a timely manner, the raw data and calculations used to develop the submitted data set and the demonstration of transmission rights to its end-use customers.

36.9.4 Eligible CRR Sources and Sinks.

Eligible CRR Sources will be the PNodes of the Generating Units or Scheduling Points for which the OCALSE has made a legitimate need showing as described above in Section 36.9.1 of this Appendix. Eligible CRR Sinks will be the Scheduling Points for which the CAISO has established Seasonal and Monthly CRR Eligible Quantities as described in Section 36.9.3 of this Appendix. An OCALSE nominating CRRs having CRR Sources internal to the CAISO Control Area will be limited to seventy-five percent (75%) of each of its corresponding Adjusted Verified CRR Source Quantities in all tiers of the annual CRR Allocation process in CRR Year One and in subsequent years. An OCALSE nominating CRRs having CRR Sources external to the CAISO Control Area will be limited to seventy-five percent (75%) of each of its corresponding Adjusted Verified CRR Source Quantities in all tiers of the annual CRR Allocation process in CRR Year One. In CRR years subsequent to CRR Year One, the OCALSE may renew previously allocated CRRs having external CRR Sources, subject to the applicable quantity limitations and other requirements specified in this Section 36.

36.9.5 Priority Nomination Process.

CRRs allocated pursuant to this Section 36.9 shall be eligible for nomination in the Priority Nomination Process to the extent that the requirements of this Section 36.9 are met at the time of the relevant CRR Allocation.

36.10 CRR Allocation to Metered Subsystems.

An MSS Operator that elects gross Settlement may participate in the CRR Allocation processes and be allocated CRR Obligations. An MSS Operator that elects net Settlement may participate in the CRR Allocation processes and be allocated CRRs, except that its Seasonal and Monthly CRR Eligible Quantities will reflect its net Load and its allocated CRRs will use MSS-LAPs as CRR Sinks. The MSS Operator will be required to submit to the CAISO the appropriate hourly historical net Load data and net Load forecast data from which the CAISO will construct net Load duration curves to determine the Seasonal and Monthly CRR Eligible Quantities.

36.11 CRR Allocation to Merchant Transmission Facilities.

Project Sponsors of Merchant Transmission Facilities who turn such facilities over to CAISO Operational Control and do not recover the cost of the transmission investment through the CAISO's Access Charge or WAC or other regulatory cost recovery mechanism may be allocated, at the Project Sponsor's election, either CRR Options or Obligations that reflect the contribution of the facility to grid transfer capacity as determined below.

36.11.1 Eligibility for Merchant Transmission CRRs.

The Project Sponsor of a Merchant Transmission Facility shall be entitled to receive Merchant Transmission CRRs as determined in accordance with this Section 36.11. A Merchant Transmission CRR allocated through this process is effective for thirty (30) years or for the pre-specified intended life of the Merchant Transmission Facility, whichever is less. Merchant Transmission CRRs represent binding commitments for thirty (30) years or for the pre-specified intended life of the Merchant Transmission Facility, whichever is less. The binding commitment by a CRR Holder that holds Merchant Transmission CRRs may not be terminated or otherwise modified by the CRR Holder prior to the end of the term of the Merchant Transmission CRR.

36.11.2 Procedure for Allocating Merchant Transmission CRRs.

No less than forty-five (45) days prior to the in-service date of a Merchant Transmission Facility, the Project Sponsor of the facility will inform the CAISO of the in-service date of the facility and that the Project Sponsor will be requesting Merchant Transmission CRRs associated with the Merchant Transmission Facility. The CAISO will complete the Merchant CRR Allocation after the in-service date of the facility and will allocate Merchant Transmission CRRs whose payment stream will be retroactive back to the in-service date.

36.11.3 Determination of Merchant Transmission CRRs to be Allocated to a Project Sponsor of a Merchant Transmission Facility.

36.11.3.1 Nominations of Merchant Transmission CRRs.

The Project Sponsor of a Merchant Transmission Facility must submit nominations for Merchant Transmission CRRs at least twenty-one (21) days prior to the in-service date of the facility. The Project Sponsor may nominate up to five individual, Point-to-Point CRRs for each of the two on-peak and off-peak time of use periods. Each of the individual, point-to-point nominations must specify: (i) a single CRR Source location; (ii) a single CRR Sink location, (iii) a MW quantity; (iv) a time of use period (on-peak or off-peak); and (v) a CRR type, either CRR Options or CRR Obligations.

36.11.3.2 Methodology to Determine Merchant Transmission CRRs.

The CAISO shall determine the incremental Merchant Transmission CRRs associated with a Merchant Transmission Facility pursuant to this Section 36.11.3.2. The determination will include an assessment of the simultaneous feasibility of the incremental Merchant Transmission CRRs and all other outstanding CRRs. The CAISO will determine the feasible incremental Merchant Transmission CRRs using a three-step process.

36.11.3.2.1 Step One: the Capability of the Existing Transmission System.

In step one the CAISO will determine the base CRR capability of the system using a Simultaneous Feasibility Test that incorporates as Fixed CRRs all existing encumbrances through the end of the CRR year for which the annual CRR Allocation and Auction process has already been conducted, including encumbrances for the month covered by the most recently conducted monthly CRR Allocation and Auction process. This analysis will determine the extent to which the nominated Merchant Transmission CRRs are feasible on the existing transmission system absent the Merchant Transmission Facility. As a result of this analysis, the CAISO will create temporary test CRR Options to reserve grid capacity that the Project Sponsor of the Merchant Transmission Facility is not eligible to receive. The temporary test CRR Options will have the same CRR Source and CRR Sink pairs as the Merchant Transmission CRR nominations submitted by the Project Sponsor.

36.11.3.2.2 Step Two: Mitigation of Impacts on Existing Encumbrances.

In the second step, the CAISO will add the proposed Merchant Transmission Facility to the DC FNM and run a SFT using the Fixed CRRs. The second step will ensure that the addition of a Merchant Transmission Facility does not negatively impact any existing encumbrances through the end of the CRR year for which the annual CRR Allocation and Auction process for Annual CRRs has already been conducted, including encumbrances for the month covered by the most recently conducted monthly CRR Allocation and Auction process. For any impacts identified in this step the Project Sponsor of the Merchant Transmission Facility will be required to mitigate the impacts for the same period. The mitigation can include having the Project Sponsor of the Merchant Transmission Facility hold counterflow CRRs that maintain the feasibility of the existing encumbrances over the same period.

36.11.3.2.3 Step Three: the Incremental Merchant Transmission CRRs.

In the third step, the CAISO will determine the Merchant Transmission CRRs to be allocated to the Project Sponsor of the Merchant Transmission Facility. The CAISO will determine the capability of the system to award incremental Merchant Transmission CRRs using a DC FNM that incorporates the proposed Merchant Transmission Facility. The CAISO will conduct separate SFTs for each time of use period. For each time of use period, the CAISO will perform a multi-period SFT that simultaneously evaluates two sets of grid conditions. The first set of grid conditions includes all existing encumbrances for the month covered by the most recently conducted CRR Allocation and Auction process for Monthly CRRs including any temporary test CRRs from step one and any counterflow CRRs from step two. The second set of grid conditions models only Transmission Ownership Rights. Each SFT will consider the entire set of Merchant Transmission CRR nominations for the time of use period and will solve to maximize the MWs of Merchant Transmission CRRs to be allocated to the Project Sponsor of the Merchant Transmission Facility, subject to simultaneous feasibility. The nominated Merchant Transmission CRRs that are feasible in the multi-period SFTs for each time of use period will be allocated to the Project Sponsor of the Merchant Transmission Facility.

36.12 [NOT USED]

36.13 CRR Auction.

The CAISO shall conduct CRR Auctions on an annual and monthly basis subsequent to each annual and monthly CRR Allocation process. Candidate CRR Holders may bid to purchase and may acquire CRR Obligations through the CAISO's annual and monthly CRR Auctions in accordance with the provisions of this Section 36.13. CRR Auction results shall be settled as provided in Section 11.2.4.3 of this Appendix.

36.13.1 Scope of the CRR Auctions.

The CAISO will conduct a CRR Auction corresponding to and subsequent to the completion of each CRR Allocation process, and prior to the start of the period to which the auctioned CRRs will apply. Each CRR Auction will release CRRs having the same seasons, months and time of use specifications as the CRRs released in the corresponding CRR Allocation. Each CRR Auction will utilize the same DC FNM that was utilized in the corresponding CRR Allocation. For each CRR Auction, the CRRs allocated in the corresponding CRR Allocation will be modeled as fixed injections and withdrawals on the DC FNM and will not be adjusted by the SFT in the CRR Auction process. Thus the CRR Auction will release only those CRRs that are feasible given the results of the corresponding CRR Allocation. CRRs released in a CRR Auction will be indistinguishable from CRRs released in the corresponding CRR Allocation for purposes of settlement and secondary trading. The following additional provisions apply. First, participants in the CRR Auctions will have more choices regarding CRR Sources and CRR Sinks than are eligible for nomination in the CRR Allocations, as described in Section 36.13.5 of this Appendix. Second, to the extent a Market Participant receives CRRs in both a CRR Allocation and the corresponding CRR Auction, the CRRs obtained in the CRR Auction will not be eligible for nomination in the PNP. Third, in CRR Year One the CRR Auction cannot be used by CRR Holders to offer for sale CRRs they acquired in a prior CRR Allocation, CRR Auction or through the Secondary Registration System. In the annual and monthly CRR Auction processes for years following CRR Year One, CRR Holders may offer for sale any CRRs held by such holders, subject to the limitations on sale and transfer of Long Term CRRs specified in Section 36.7.1.2 of this Appendix. Merchant Transmission CRRs that are CRR Options may be offered for sale in the annual and monthly CRR Auctions for years following CRR Year One, subject to the same temporal limitations that apply to Long Term CRRs as specified in Section 36.7.1.2 of this Appendix.

36.13.2 Responsibilities of the CAISO Prior to Each CRR Auction.

The CAISO shall publish on the CAISO Website a notice of upcoming CRR Auctions at least seven (7) days prior to the CRR Auction. The CAISO will also provide additional information needed by CRR Auction participants in accordance with the provisions of Section 6.5.1 of this Appendix.

36.13.3 CRR Holder Creditworthiness.

All Market Participants are eligible to acquire CRRs by participating in the CRR Auction, provided that the Market Participant has met all the CRR Holder requirements described in Section 36.5, the creditworthiness provisions in Section 12 of the CAISO Tariff and Section 12.6 of this Appendix and the relevant Business Practice Manual.

36.13.4 Bids in the CRR Auctions.

Bids to purchase CRRs shall be submitted in accordance with the requirements set out in this Section 36.13.4 and as further specified in the applicable Business Practice Manuals. Once submitted to the CAISO, CRR bids may not be cancelled or rescinded by the Market Participant after the CRR Auction is closed. Market Participants may bid for Point-to-Point CRRs and Multi-Point CRRs. Each bid for a Point-to-Point CRR shall specify:

- a) The associated month or season and time of use period;
- b) The associated CRR Source and CRR Sink;
- c) A monotonically non-increasing piecewise linear bid curve in quantities (denominated in **thousandths** of a MW) and prices (\$/MW).

Each bid for a Multi-Point CRR shall specify:

- d) The associated month or season and time of use period;
- e) The associated CRR Sources and CRR Sinks;
- f) For each CRR Source, a monotonically non-decreasing piecewise linear bid curve in quantities (denominated in *thousandths* of a MW) and prices (\$/MW).
- g) For each CRR Sink, a monotonically non-increasing piecewise linear bid curve in quantities (denominated in *thousandths* of a MW) and prices (\$/MW).

Bid prices in all CRR bids may be negative.

36.13.5 Eligible Sources and Sinks for CRR Auction.

Allowable CRR Sources for CRRs acquired in the CRR Auction will be PNodes, Scheduling Points, Trading Hubs, LAPs, MSS-LAPs and Sub-LAPs. Allowable CRR Sinks for CRRs acquired in the CRR Auction will be PNodes, Scheduling Points, Trading Hubs, LAPs, MSS-LAPs and Sub-LAPs.

36.13.6 Clearing of the CRR Auction.

The SFT used to clear the CRR Auction will utilize the same DC FNM and optimization algorithm as the corresponding CRR Allocation, except that nominations to the CRR Auction will have associated price-quantity bid curves. The CRR Auction SFT will use the bid prices in determining which CRRs to award when not all nominations are simultaneously feasible, will select the set of simultaneously feasible CRRs with the highest total auction value as determined by the CRR bids, and will calculate nodal prices at each PNode of the DC FNM. In the event that there are two or more identical bids for a specific

combination of CRR Source and CRR Sink that affect an overloaded constraint, the CRR Auction optimization cannot distinguish these bids based on either effectiveness or price and therefore the CRR Auction optimization will award each CRR bidder a pro rata share of the CRRs that can be awarded based on the bid MW amounts. Based on the nodal prices calculated by the CRR Auction SFT, the CRR Market Clearing Price per MW for a specific CRR will equal the nodal price at the CRR Sink minus the nodal price at the CRR Source. For a Multi-Point CRR the CRR Market Clearing Price will equal the sum over all relevant CRR Sinks of the nodal price at each CRR Sink times that CRR Sink's share of the total MW of the CRR, minus the sum over all relevant CRR Sources of the nodal price at each CRR Source times that CRR Source's share of the total MW of the CRR Market Participants shall pay the associated CRR Market Clearing Prices for all CRRs bought through the CRR Auction.

36.13.7 Announcement of CRR Auction Results.

Within five (5) Business Days after the close of a CRR Auction, the CAISO shall post the results. The results shall include but are not limited to the MW quantity, the CRR Source and CRR Sink for each CRR awarded, the nodal prices calculated by the CRR Auction SFT, and the parties to whom the CRRs were awarded. The CAISO shall not disclose prices specified in any CRR bid.

PART I. MISCELLANEOUS SECTIONS

11.2.4.3 Payments and Charges for Monthly and Annual Auctions.

The CAISO shall charge CRR Holders for the market clearing price for CRRs obtained through the clearing of the CRR Auction as described in Section 36.13.6 of this Appendix. To the extent the CRR Holder purchases a CRR through a CRR Auction that has a negative value, the CAISO shall pay the CRR Holder for taking the applicable CRR. The CAISO shall net all revenue received and payments made through this process and shall add the net remaining seasonal and monthly CRR Auction revenue amounts (either negative or positive amounts) to the CRR Balancing Account for the appropriate month. CRR Auction revenues for each season are allocated uniformly across the three monthly accounts comprising each season.

24.7.3 Provided that the CAISO has Operational Control of the Merchant Transmission Facility, a Project Sponsor that does not recover the investment cost under a FERC-approved rate through the Access Charge or a reimbursement or direct payment from a Participating TO shall be entitled to receive Merchant CRRs as provided in Section 36.11 of this Appendix. The full amount of capacity added to the system by such transmission upgrades or additions will be as determined through the regional reliability council process of the Western Electricity Coordinating Council or its successor. Pursuant to its Project Sponsor status as specified in Section 4.3.1.3, consistent with FERC's findings in Docket Nos. EL04-133-001, ER04-1198-000, and ER04-1198-001, issued on May 16, 2006 (115 FERC ¶ 61,178), Western Path 15 shall receive compensation associated with transmission usage rights modeled for Western Path 15. In the event that Western Path 15 has an approved rate schedule that returns excess revenue from any compensation obtained from the CAISO associated with the transmission usage rights for Western Path 15, such revenue shall be returned to the CAISO through a procedure established by the CAISO and the Western Area Power Administration for that purpose.

PART J. PRO FORMA MSS AGGREGATOR CRR ENTITY AGENT AGREEMENT

The provisions of this Part J are necessary to enable the CAISO to establish the terms of a *pro forma* service agreement by which the CAISO will enter into a direct relationship with MSS Aggregators that desire to participate in the CRR Allocation and CRR Auction to be conducted in the summer and fall of 2007.

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

AND

[METERED SUBSYSTEM AGGREGATOR]

MSS AGGREGATOR CRR ENTITY AGENT AGREEMENT

MSS AGGREGATOR CRR ENTITY AGENT AGREEMENT

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

(1) **[INSERT NAME OF MSS AGGREGATOR]**, a **[INSERT TYPE OF ENTITY]**, having its registered and principal place of business located at **[INSERT ADDRESS]**, acting as the agent on behalf of the following principals: **[INSERT NAMES OF MSS OPERATOR LSEs]**, all of which are MSS Operators and Load Serving Entities, ("MSS Operators") pursuant to the terms of that certain **[INSERT TITLE OF MSS AGGREGATOR AGREEMENT]** ("MSSAA") dated _____ (the "CRR Entity Agent");

and

(2) **California Independent System Operator Corporation**, a California nonprofit public benefit corporation having a principal executive office located at such place in the State of California as the CAISO Governing Board may from time to time designate, initially 151 Blue Ravine Road, Folsom, California 95630 (the "CAISO").

The CRR Entity Agent and the CAISO are hereinafter referred to individually as a "Party" and collectively as the "Parties."

Whereas:

- A.** The CAISO Tariff provides that any entity that holds or intends to hold CRRs must register and qualify with the CAISO and comply with the terms of the CAISO Tariff (either directly or through its agent), regardless of whether they are to acquire CRRs through the CRR Allocation or CRR Auction, or through the Secondary Registration System.
- B.** The CRR Entity Agent pursuant to the terms of the MSSAA is authorized by the aggregated MSS Operators to act on the behalf of the MSS Operators with regard to matters relating to CRRs, including, but not limited to, allowing the CRR Entity Agent to participate in the CRR nomination process on behalf of the MSS Operators, to accept financial responsibility under this Agreement, to perform settlement functions, and to comply with CAISO Tariff requirements.
- C.** The CRR Entity Agent has completed the Candidate CRR Holder application process on behalf of its aggregated MSS Operators and pursuant to the terms of the MSSAA is eligible to participate on behalf of the MSS Operators in the CRR Allocation or CRR Auction or register through the Secondary Registration System on behalf of the MSS Operators. However, the CRR Entity Agent will not hold title to or ownership of any CRRs issued to any of its aggregated MSS Operators through the CRR Allocation, CRR Auction, or Secondary Registration System processes. Rather, the CRR Entity Agent will hold title for the CRRs allocated to the individual MSS Operator's Load in trust on behalf of the MSS Operator.
- D.** The CAISO Tariff further provides that any entity that wishes to participate in the CRR Allocation or CRR Auction or register as a CRR Holder through the Secondary Registration System must meet all of the Candidate CRR Holder requirements and creditworthiness provisions in the CAISO Tariff and the relevant Business Practice Manual, including demonstration of its ability to accommodate the financial responsibility associated with holding CRRs.
- E.** The aggregated MSS Operators desire to act through the CRR Entity Agent to comply with all requirements referenced in part D, above, in order to obtain CRRs through the CRR Allocation, CRR Auction, or Secondary Registration System.

- F.** The CRR Entity Agent, on behalf of its aggregated MSS Operators, wishes to undertake such necessary tasks and requirements set forth herein to comply with the applicable provisions of the CAISO Tariff in order to allow the MSS Operators to participate in the CRR Allocation, CRR Auction, and Secondary Registration System processes.
- G.** The Parties are entering into this Agreement in order to establish the terms and conditions pursuant to which the CAISO and the CRR Entity Agent will discharge their respective duties and responsibilities under the CAISO Tariff.

NOW THEREFORE, in consideration of the mutual covenants set forth herein, **THE PARTIES AGREE** as follows:

ARTICLE I DEFINITIONS AND INTERPRETATION

- 1.1 Master Definitions Supplement.** All terms and expressions used in this Agreement shall have the same meaning as those contained in the Master Definitions Supplement in Appendix A of the CAISO Tariff, unless otherwise defined herein.
- 1.2 Rules of Interpretation.** The following rules of interpretation and conventions shall apply to this Agreement:
- (a) if there is any inconsistency between this Agreement and the CAISO Tariff, the CAISO Tariff will prevail to the extent of the inconsistency;
 - (b) the singular shall include the plural and vice versa;
 - (c) the masculine shall include the feminine and neutral and vice versa;
 - (d) "includes" or "including" shall mean "including without limitation";
 - (e) references to a Section, Article, or Schedule shall mean a Section, Article, or a Schedule of this Agreement, as the case may be, unless the context otherwise requires;
 - (f) a reference to a given agreement 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;
 - (g) unless the context otherwise requires, references to any law shall be deemed references to such law as it may be amended, replaced, or restated from time to time;
 - (h) unless the context otherwise requires, any reference to a "person" includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization, or other entity, in each case whether or not having separate legal personality;
 - (i) unless the context otherwise requires, any reference to a Party includes a reference to its permitted successors and assigns;

- (j) any reference to a day, week, month, or year is to a calendar day, week, month, or year; and
- (k) the captions and headings in this Agreement are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Agreement.

ARTICLE II ACKNOWLEDGEMENTS OF CRR ENTITY AGENT AND CAISO

- 2.1 Scope of Application to Parties.** The CRR Entity Agent and CAISO acknowledge that all MSS Aggregators that are authorized by their aggregated MSS Operators to act as the agent of those MSS Operators in undertaking all obligations and responsibilities of Candidate CRR Holders or CRR Holders must sign this Agreement in accordance with section 4.10.1.9.1 of the CAISO Tariff.

ARTICLE III TERM AND TERMINATION

- 3.1 Effective Date.** This Agreement shall be effective as of the later of the date it is executed by both Parties or the date accepted for filing and made effective by FERC if such FERC filing is required, and shall remain in full force and effect until terminated pursuant to Section 3.2 of this Agreement.
- 3.2 Termination**
- 3.2.1 Termination by CAISO.** Upon notice that the agency relationship between all of the aggregated MSS Operators and the CRR Entity Agent has terminated, including any notice that the MSSAA has terminated, the CAISO may terminate this Agreement by giving written notice to the CRR Entity Agent of termination. Further, subject to Article V, the CAISO may terminate this Agreement by giving written notice to the CRR Entity Agent of termination in the event that the CRR Entity Agent commits any material default under this Agreement and/or the CAISO Tariff as it pertains to this Agreement which, if capable of being remedied, is not remedied within thirty (30) days after the CAISO has given, to the CRR Entity Agent, written notice of the default, unless excused by reason of Uncontrollable Forces in accordance with Article X of this Agreement or unless the CAISO agrees, in writing, to an extension of the time to remedy such material default. With respect to any notice of termination given pursuant to this Section, the CAISO must file a timely notice of termination with FERC, if this Agreement was filed with FERC, or must otherwise comply with the requirements of FERC Order No. 2001 and related FERC orders. The filing of the notice of termination by the CAISO with FERC will be considered timely if: (1) the filing of the notice of termination is made after the preconditions for termination have been met and (2) the CAISO files the notice of termination within sixty (60) days after issuance of the notice of default or (3) the CAISO files the notice of termination in accordance with the requirements of FERC Order No. 2001. This Agreement shall terminate upon acceptance by FERC of such a notice of termination, if filed with FERC, or thirty (30) days after the date of the CAISO's notice of default, if terminated in accordance with the requirements of FERC Order No. 2001 and related FERC orders.

3.2.2 Termination by CRR Entity Agent. In the event that the CRR Entity Agent is no longer a CRR Holder as trustee for any or all of its aggregated MSS Operators, the CRR Entity Agent may terminate this Agreement, on giving the CAISO not less than ninety (90) days' written notice; provided, however, any outstanding financial right or obligation or any other obligation under the CAISO Tariff of the Candidate CRR Holder or CRR Holder (regardless of whether such obligation shall be borne by an aggregated MSS Operator or the CRR Entity Agent) that has arisen while the CRR Entity Agent was a Candidate CRR Holder or a CRR Holder as trustee for any or all of its MSS Operators, and any provision of this Agreement necessary to give effect to such right or obligation, shall survive until satisfied. With respect to any notice of termination given pursuant to this Section, CAISO must file a timely notice of termination with FERC, if this Agreement has been filed with FERC, or must otherwise comply with the requirements of FERC Order No. 2001 and related FERC orders. The filing of the notice of termination by the CAISO with FERC will be considered timely if: (1) the request to file a notice of termination is made after the preconditions for termination have been met and (2) the CAISO files the notice of termination within sixty (60) days after receipt of such request or (3) the CAISO files the notice of termination in accordance with the requirements of FERC Order No. 2001. This Agreement shall terminate upon acceptance by FERC of such a notice of termination, if such notice is required to be filed with FERC, or upon ninety (90) days after the CAISO's receipt of the CRR Entity Agent's notice of termination, if terminated in accordance with the requirements of FERC Order No. 2001 and related FERC orders.

ARTICLE IV GENERAL TERMS AND CONDITIONS

- 4.1 CRR Holder Requirements.** The CRR Entity Agent acting on behalf of its aggregated MSS Operators must register and qualify on behalf of the MSS Operators with the CAISO and comply with all terms of the CAISO Tariff applicable to Candidate CRR Holders or CRR Holders, regardless of the manner in which it acquires the CRRs on behalf of its aggregated MSS Operators, whether by CRR Allocation or CRR Auction, or through the Secondary Registration System. The CRR Entity Agent shall participate in the CRR nomination process on an aggregated basis on behalf of each of its aggregated MSS Operators on the basis of that individual MSS Operator's Load ratio share set forth in Schedule 3. The CAISO shall allocate CRRs to each individual MSS Operator based on its Load ratio share set forth in Schedule 3, which CRRs will be held in the aggregate by the CRR Entity Agent on behalf of its aggregated MSS Operators. The CRR Entity Agent acknowledges and agrees that it shall not hold title to or ownership of any of the CRRs of its aggregated MSS Operators. Ownership and title of any obtained CRRs shall be held in trust by the CRR Entity Agent on behalf of the applicable MSS Operator in accordance with each MSS Operator's Load share ratio as set forth in Schedule 3.
- 4.2 CRR Holder Creditworthiness Requirements.** The CRR Entity Agent acting on behalf of its aggregated MSS Operators must comply with the requirements for creditworthiness applicable to Candidate CRR Holders or CRR Holders, including the creditworthiness provisions of the CAISO Tariff and the relevant Business Practice Manual.
- 4.3 Settlement Account.** The CRR Entity Agent on behalf of its aggregated MSS Operators shall maintain at all times an account with a bank capable of Fed-Wire transfer to which credits or debits shall be made in accordance with the billing and Settlement provisions of Section 11 of the CAISO Tariff. Such account shall be the account referred to in Schedule 2 hereof or as notified by the CRR Entity Agent to the CAISO from time to time by giving at least seven (7) days written notice before the new account becomes operational. Such changes to Schedule 2 shall not constitute an amendment to this Agreement.

- 4.4 CRR Entity Agent Responsibility for MSS Operator Load Share Ratio.** The CRR Entity Agent shall track each aggregated MSS Operator's Load share ratio of CRRs separately as set forth in Schedule 3 and shall be solely responsible for tracking such allocations. The CRR Entity Agent acknowledges and agrees that CAISO shall have no responsibility with regard to such pro rata allocations of CRRs as set forth in Schedule 3. The CAISO shall issue CRRs allocated to the aggregated MSS Operators in aggregate to the CRR Entity Agent, and the CRR Entity Agent shall be solely responsible for ensuring the proper allocation of such CRRs to each aggregated MSS Operator. In the event the MSS Operator and CRR Entity Agent aggregation or agency relationship terminates, the CRR Entity Agent shall be solely responsible for ensuring that the appropriate pro rata share of every CRR Source is properly assigned to the applicable MSS Operator.
- 4.5 Provision of Evidence of CRR Entity Agent Authority.** The CRR Entity Agent shall provide the CAISO with a copy of the MSSAA or other sufficient evidence to assure the CAISO of its authority to act as agent on behalf of its aggregated MSS Operators with regard to the matters addressed in this Agreement. The CRR Entity Agent shall provide the CAISO with the contact name, address, e-mail address, and phone number of an individual representative of each of its aggregated MSS Operators whom the CAISO may contact regarding matters addressed in this Agreement. The CRR Entity Agent shall immediately notify the CAISO in writing of any revision to the terms of the MSSAA that affects its authority to act as agent on behalf of its aggregated MSS Operators or any other change in its relationship with any of its aggregated MSS Operators.
- 4.6 Electronic Contracting.** All submitted applications, bids, confirmations, changes to information on file with the CAISO and other communications conducted via electronic transfer (*e.g.*, direct computer link, FTP file transfer, bulletin board, e-mail, facsimile or any other means established by the CAISO) shall have the same legal rights, responsibilities, obligations and other implications as set forth in the terms and conditions of the CAISO Tariff as if executed in written format.
- 4.7 Agreement Subject to CAISO Tariff.** The Parties will comply with all provisions of the CAISO Tariff applicable to Candidate CRR Holders or CRR Holders. This Agreement shall be subject to the CAISO Tariff, which shall be deemed to be incorporated herein.

ARTICLE V PERFORMANCE

- 5.1 Penalties.** The CRR Entity Agent on behalf of its aggregated MSS Operators shall be subject to all penalties made applicable to Candidate CRR Holders and CRR Holders set forth in the CAISO Tariff. Nothing in this Agreement, with the exception of the provisions relating to ADR, shall be construed as waiving the rights of the CRR Entity Agent on behalf of its aggregated MSS Operators to oppose or protest the specific imposition by the CAISO of any FERC-approved penalty on the CRR Entity Agent or any MSS Operator.
- 5.2 Corrective Measures.** If the CRR Entity Agent or the CAISO fails to meet or maintain the requirements set forth in this Agreement and/or the CAISO Tariff, the CAISO or the CRR Entity Agent shall be permitted to take any of the measures, contained or referenced in the CAISO Tariff as it pertains to this Agreement, which the Party seeking enforcement deems to be necessary to correct the situation.

**ARTICLE VI
COSTS**

- 6.1 Operating and Maintenance Costs.** The CRR Entity Agent shall be responsible for all its costs and any costs of its aggregated MSS Operators incurred in connection with all its CRR related activities.

**ARTICLE VII
DISPUTE RESOLUTION**

- 7.1 Dispute Resolution.** The Parties shall make reasonable efforts to settle all disputes arising out of or in connection with this Agreement. In the event any dispute is not settled, the Parties shall adhere to the ISO ADR Procedures set forth in Section 13 of the CAISO Tariff, which is incorporated by reference, except that any reference in Section 13 of the CAISO Tariff to Market Participants shall be read as a reference to one or more aggregated MSS Operators and/or the CRR Entity Agent (as applicable) and references to the CAISO Tariff shall be read as references to this Agreement.

**ARTICLE VIII
REPRESENTATIONS AND WARRANTIES**

- 8.1 Representation and Warranties.** Each Party represents and warrants that the execution, delivery and performance of this Agreement by it has been duly authorized by all necessary corporate and/or governmental actions, to the extent authorized by law, and that the proper agreements providing for the CRR Entity Agent relationship with each aggregated MSS Operator, including, but not limited to, the MSSAA, are in full force and effect.

**ARTICLE IX
LIABILITY**

- 9.1 Liability.** The provisions of Section 14 of the CAISO Tariff will apply to liability arising under this Agreement, except that all references in Section 14 of the CAISO Tariff to Market Participants shall be read as references to one or more aggregated MSS Operators and/or the CRR Entity Agent (as applicable), and references to the CAISO Tariff shall be read as references to this Agreement. Further, in reliance on the agency relationship between the CRR Entity Agent and each aggregated MSS Operator, CAISO shall treat the CRR Entity Agent as the MSS Operators and shall not be liable to any aggregated MSS Operator for any claims, liabilities, or errors arising from this agency relationship, including, but not limited to, CRR ownership or Settlement Accounts, unless the CAISO causes such claim(s), liability(ies) or error(s) due to its gross negligence or willful conduct.

**ARTICLE X
UNCONTROLLABLE FORCES**

- 10.1 Uncontrollable Forces Tariff Provisions.** Section 14.1 of the CAISO Tariff shall be incorporated by reference into this Agreement except that all references in Section 14.1 of the CAISO Tariff to Market Participants shall be read as a reference to one or more aggregated MSS Operators and/or the CRR Entity Agent (as applicable) and references to the CAISO Tariff shall be read as references to this Agreement.

**ARTICLE XI
MISCELLANEOUS**

- 11.1 Assignments.** Either Party may assign or transfer any or all of its rights and/or obligations under this Agreement with the other Party's prior written consent in accordance with Section 22.2 of the CAISO Tariff and other CAISO Tariff requirements as applied to Candidate CRR Holders or CRR Holders. Such consent shall not be unreasonably withheld. Any such transfer or assignment shall be conditioned upon the successor in interest accepting the rights and/or obligations under this Agreement as if said successor in interest was an original Party to this Agreement.
- 11.2 Notices.** Any notice, demand, or request which may be given to or made upon either Party regarding this Agreement shall be made in accordance with Section 22.4 of the CAISO Tariff. A Party must update the information in Schedule 1 of this Agreement as information changes. Such changes to Schedule 1 shall not constitute an amendment to this Agreement.
- 11.3 Waivers.** Any waivers at any time by either 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.
- 11.4 Governing Law and Forum.** This Agreement shall be deemed to be a contract made under, and for all purposes shall be governed by and construed in accordance with, the laws of the State of California, except its conflict of law provisions. The Parties irrevocably consent that any legal action or proceeding arising under or relating to this Agreement to which the ISO ADR Procedures do not apply, shall be brought in any of the following forums, as appropriate: (i) any court of the State of California, (ii) any federal court of the United States of America located in the State of California, except to the extent subject to the protections of the Eleventh Amendment of the United States Constitution, or (iii) where subject to its jurisdiction, before the Federal Energy Regulatory Commission.
- 11.5 Consistency with Federal Laws and Regulations.** This Agreement shall incorporate by reference Section 22.9 of the CAISO Tariff as if the references to the CAISO Tariff were referring to this Agreement.
- 11.6 Merger.** This Agreement constitutes the complete and final agreement of the Parties with respect to the subject matter hereto and supersedes all prior agreements, whether written or oral, with respect to such subject matter.
- 11.7 Severability.** If any term, covenant, or condition of this Agreement or the application or effect of any such term, covenant, or condition is held invalid as to any person, entity, or circumstance, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in force and effect to the maximum extent permitted by law, and all other terms, covenants, and conditions of this Agreement and their application shall not be affected thereby, but shall remain in force and effect and the Parties shall be relieved of their obligations only to the extent necessary to eliminate such regulatory or other determination unless a court or governmental agency of competent jurisdiction holds that such provisions are not separable from all other provisions of this Agreement.

11.8 Section Headings. Section headings provided in this Agreement are for ease of reading and are not meant to interpret the text in each Section.

11.9 Amendments. This Agreement and the Schedules attached hereto may be amended from time to time by the mutual agreement of the Parties in writing. Amendments that require FERC approval shall not take effect until FERC has accepted such amendments for filing and made them effective. If the amendment does not require FERC approval, the amendment will be filed with FERC for informational purposes. Nothing herein shall be construed as affecting in any way the right of the CAISO to make unilateral application to FERC for a change in the rates, terms, and conditions of this Agreement under Section 205 of the FPA and pursuant to FERC's rules and regulations promulgated thereunder. The standard of review the Commission shall apply when acting upon proposed modifications to this Agreement by the CAISO shall be the "just and reasonable" standard of review rather than the "public interest" standard of review. The standard of review the Commission shall apply when acting upon proposed modifications to this Agreement by the Commission's own motion or by a signatory other than the CAISO or non-signatory entity shall also be the "just and reasonable" standard of review. Schedules 1 and 2 are provided for informational purposes and revisions to those schedules do not constitute a material change in the Agreement warranting Commission review.

11.10 Counterparts. This Agreement may be executed in one or more counterparts at different times, each of which shall be regarded as an original and all of which, taken together, shall constitute one and the same Agreement.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be duly executed on behalf of each by and through their authorized representatives as of the date hereinabove written.

California Independent System Operator Corporation

By: _____

Name: _____

Title: _____

Date: _____

[INSERT NAME OF CRR ENTITY AGENT]

By: _____

Name: _____

Title: _____

Date: _____

SCHEDULE 1

NOTICES

[Section 11.2]

CRR Entity Agent

Name of Primary

Representative:

Title:

Company:

Address:

City/State/Zip Code:

Email Address:

Phone:

Fax No:

Name of Alternative

Representative:

Title:

Company:

Address:

City/State/Zip Code:

Email Address:

Phone:

Fax No:

CAISO

Name of Primary

Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email address: _____

Phone: _____

Fax: _____

Name of Alternative

Representative: _____

Title: _____

Address: _____

City/State/Zip Code: _____

Email address: _____

Phone: _____

Fax: _____

SCHEDULE 2

SETTLEMENT ACCOUNT

[Section 4.3]

CRR Entity Agent Account Information

Settlement Account No:

Title:

Sort Code:

Bank:

SCHEDULE 3

[Pro Rata Load Share per MSS Operator Represented by CRR Entity Agent]

[Section 4.4]

PART K. SETTLEMENT OF PREPAYMENTS BY OUT-OF-CONTROL AREA LOAD SERVING ENTITIES TO OBTAIN CRRS THROUGH THE CRR ALLOCATION PROCESS

The provisions below are included in this Appendix BB in order to enable the CAISO to: 1) settle any pre-payments made by an OCALSE that obtained CRRs through the CRR Allocation process for 2008 as required in Section 36.9 of this Appendix, and also, 2) in instances where the terms of the allocated CRRs were reduced prior to the start of MRTU re-settle any such amounts consistent with the reduced terms of the allocated CRRs.

11.2.5 Payment by Out-of-Control Area Load Serving Entity to Obtain CRRs Through the CRR Allocation Process.

11.2.5.1 Pursuant to Section 36.9, in addition to other requirements specified therein, an OCALSE will be eligible to participate in the CRR Allocation process if such entity has made a pre-payment to the CAISO and has met the requirements in Section 36.9. The prepayment amount shall equal the MW of CRR requested times the Wheeling Access Charge associated with the Scheduling Point corresponding to the CRR Sink times the number of hours in the period for each requested CRR MW amount. Except as provided in Section 39.9.2, such prepayment will be made three (3) Business Days in advance of the submission of CRR nominations for Monthly CRRs, Seasonal CRRs and Long Term CRRs to the CRR Allocation. Within thirty (30) days following the completion of the CRR Allocation process for Monthly CRRs, Seasonal CRRs and Long Term CRRs, the CAISO shall reimburse such OCALSE the amount of money pre-paid for any CRRs that were not allocated to the entity. To the extent that an OCALSE has prepaid Wheeling Access Charges, pursuant to Section 36.9 of this Appendix BB, for CRRs that have been reduced in term pursuant to Section 44.1, such Wheeling Access Charges shall be refunded to the OCALSE to reflect the reduction in term of the applicable CRRs.

11.2.5.3 Monthly Prepayment Option.

If the OCALSE qualified for the monthly prepayment option as specified in Section 36.9.2, the OCALSE shall make its payments consistent with the monthly prepayment schedule specified in the applicable Business Practice Manual.

PART L. CRR CONTINGENCY PLAN

Pursuant to the terms provided in this Part L of this Appendix, the CAISO shall: 1) reduce the terms of Seasonal CRRs and Long Term CRRs previously released through the annual CRR Allocation and Seasonal CRRs released through the CRR Auction to eliminate those months of their terms prior to when the CAISO will be operating under the MRTU Tariff as provided in Section 44.1; 2) resettle CRR Auction payments received or paid by the CAISO for positively or negatively valued CRRs, respectively, that were released through the annual CRR Auction as provided in Section 44.2; and 3) in the event that the CAISO cannot release Firm Transmission Rights through the FTR auction for the month of April or the month of May 2008, make FTRs available to eligible entities as further provided below in Section 44.2.

44 Reduction of CRR Terms and Resettlement of Reduced Term CRRs.

44.1 Reduction in Term of CRRs for 2008.

The terms of Seasonal CRRs released in the annual CRR Allocation or CRR Auction for 2008 and Long Term CRRs released in the annual CRR Allocation will be reduced to eliminate those months of their terms prior to the date on which the CAISO begins operations under the MRTU Tariff. For each CRR so reduced, the new term will begin at the start of the first hour of that CRR's time of use period in which the CAISO begins operations under the MRTU Tariff, and will end at that CRR's originally specified expiration. In the event that the CAISO begins operations under the MRTU Tariff after the originally specified expiration of a CRR, the term of that CRR will be reduced to zero.

44.2 Adjustment of the CRR Auction Settlement for CRRs with Reduced Terms.

For a CRR released in the CRR Auction for 2008 whose term is reduced pursuant to Section 44.1, the CAISO will calculate an adjustment to the CRR Auction Settlement by: 1) dividing the number of hours (on-peak or off-peak) that the term of the CRR was reduced by the number of hours (on-peak or off-peak) in the original term, and then 2) multiplying this ratio by the original CRR Auction Settlement amount for the CRR. To the extent that an adjustment to a CRR Auction Settlement is a positive amount, such amount will represent a payment due from the CAISO to the entity that received the CRR in the annual CRR Auction for 2008. To the extent that an adjustment to a CRR Auction Settlement is a negative amount, such adjustment shall represent a charge due to the CAISO from the entity who received the CRR in the CRR Auction for 2008.

44.2.1 Timing of Reduction, Resettlement and Invoicing.

44.2.1.1 Timing of Reduction and Resettlement Before CAISO Establishes Start-up Date for the MRTU Day-Ahead Market.

Commencing on April 1, 2008, and continuing until such time that the CAISO has announced the date on which it anticipates that it will begin operations under the MRTU Tariff through a CAISO Market Notice, the CAISO will, for each month during which the MRTU Tariff is not in effect: 1) for any CRRs released through the CRR Allocation and CRR Auction for 2008 that were originally scheduled to be in effect during that month, reduce the terms of such CRRs by one month as provided in Section 44.1, and 2) for any CRRs released through the CRR Auction for 2008 that were originally scheduled to be in effect during that month, adjust the CRR Auction Settlement as provided in Section 44.2. All adjustments to CRR Auction Settlements, as applicable, will apply to and will be netted for each CRR Holder that was originally awarded the CRRs in the first annual CRR Auction for 2008. The CAISO shall reflect any resulting payments or charges in a subsequent invoice per the ISO Payments Calendar as soon as practicable. The CAISO will calculate and include interest in the invoiced Settlement adjustments, as set forth in Section 44.2.2.

44.2.1.2 Timing of Reduction and Resettlement After CAISO Establishes the Date on which it Will Begin Operations under the MRTU Tariff.

As of April 1, 2008, and after such time that the CAISO has through a CAISO Market Notice announced either (1) the anticipated date on which it will begin operations under the MRTU Tariff, or (2) a date before which it will definitely not begin operations under the MRTU Tariff, the CAISO shall determine the number of months that remain in 2008 prior to the announced date and for which CRR term reduction and CRR Auction resettlement have not already been performed, and will perform the term reduction and CRR Auction resettlement for this time period as a whole in a one-time process. The CAISO shall reduce the terms of CRRs as provided in Section 44.1 and calculate CRR Auction resettlements as provided in Section 44.2 for the full remaining time period. These CRR Auction resettlements will be reflected in a subsequent invoice per the ISO Payments Calendar as soon as practicable after the date on which the CAISO announces either of the dates described above.

44.2.2 Interest on Payments and Charges for Reduced Terms of CRRs Released Through the CRR Auction.

As part of the calculation of CRR Auction Settlement adjustments for each affected CRR Holder, the CAISO shall calculate associated interest payments and charges in such a manner as to: (1) apply the same effective interest rate and interest period to holders of positively-valued and negatively-valued CRRs; and (2) ensure that the CAISO realizes neither a surplus nor a deficit of funds for any month for which CRR Auction Settlement adjustments are required. To accomplish these objectives the CAISO will calculate the interest payments and charges due to CRR Holders based on the effective interest rate the CAISO earned on the CRR Auction revenue amounts held in the monthly CRR Balancing Accounts, for the time period during which the CAISO earned interest on those amounts. Interest on a positively valued CRR will represent interest owed by the CAISO to the entity to whom the affected CRR was originally released in the CRR Auction for 2008. Interest on a negatively valued CRR will represent interest due to the CAISO from the entity who obtained the CRR in the 2008 CRR Auction.

45 Firm Transmission Rights Additional Measures.

45.1 FTRs Awarded to New Participating TOs Under Section 36.4.3.

FTRs awarded to New Participating TOs until the end of the transition period (December 31, 2010) under Section 36.4.3 will be extended until the earlier of the start-up date for MRTU or the end of 2010.

45.2 Reduction of Terms of Firm Transmission Rights when MRTU Tariff is in Effect.

After the CAISO commences operations under the MRTU Tariff, for any FTRs that are still effect at such time, the CAISO shall reduce the terms of any FTRs that were released for any hours beginning at 12:00 a.m., on April 1, 2008 and ending at 11:00p.m., on March 31, 2009 p.m., for any month that the CAISO is operating under the MRTU Tariff. The CAISO shall also refund to the FTR Holders the FTR auction Settlement amounts associated with the reduced terms of the FTRs proportionately. The CAISO shall reflect any resulting payments in a subsequent invoice per the ISO Payments Calendar as soon as practicable. The amount of interest to be paid to each party that was awarded FTRs in the FTR auction that are reduced in term shall be determined so that for each month for which the FTR auction is resettled the CAISO will realize neither a shortfall nor a surplus of funds and all affected FTR Holders will receive the same effective interest rate for the month. Thus the effective interest rate paid to the affected FTR Holders shall be based on the interest rate the CAISO has earned on amounts held in the monthly FTR auction accounts.

PART M. CRR MONITORING AND AFFILIATE DISCLOSURE REQUIREMENTS

39.9 CRR Monitoring and Affiliate Disclosure Requirements.

The CAISO will monitor the CRR holdings and CAISO Markets activity for anomalous market behavior, gaming, or exercise of market power resulting from CRR ownership concentrations that are not aligned with actual transmission usage as a result of secondary market auction outcomes. If the CAISO identifies such behavior it may seek FERC approval to impose position limits on the total number or MW quantity of CRRs that may be held by any single entity and its Affiliates. Each CRR Holder or Candidate CRR Holder must notify the CAISO of all entities that are Affiliates or become Affiliates of the CRR Holder or Candidate CRR Holder.

ISO TARIFF APPENDIX CC

For the purpose of enforcing Market Participant compliance with the forward reporting activities associated with resource adequacy and to enable the CAISO to assign Local Capacity Area Resource responsibility prior to the effective date of the CAISO Tariff as filed in FERC Docket No. ER06-615 and ER07-1257, the CAISO shall operate pursuant to this Appendix CC. This Appendix CC is included in the ISO Tariff to set forth temporary provisions that are based on tariff authority conditionally accepted in FERC Docket No. ER06-615 and as filed in Docket No. ER07-1257. These provisions enable the CAISO to: 1) require Load Serving Entities to elect between Reserving Sharing LSE and Modified Reserve Sharing LSE options; 2) define the information requirements for resource adequacy programs and the two Load Serving Entity options that must be provided to the CAISO; 3) require the submission from Load Serving Entities of monthly and annual Resource Adequacy Plans that set forth information, including identification of Local Capacity Area Resources; 4) determine the minimum amount of Local Capacity Area Resources needed in Local Capacity Areas and allocate responsibility to Load Serving Entities for such Local Capacity Area Resources; 5) require the registration of Use-Limited Resources and the submission of use plans by Use-Limited Resources; and 6) apply default resource counting protocols. This Appendix CC, therefore, does not replace or supersede those provisions contained in the ISO Tariff.

PART A – RESOURCE ADEQUACY

**40 RESOURCE ADEQUACY DEMONSTRATION FOR ALL SCHEDULING
COORDINATORS SCHEDULING DEMAND IN THE CAISO CONTROL AREA.**

40.1 Applicability.

A Load Serving Entity, and its Scheduling Coordinator, shall be exempt from Section 40 of this appendix, if the metered peak Demand of the Load Serving Entity did not exceed one (1) MW during the twelve months preceding the last date on which the Load Serving Entity can make the election in Section 40.1.1 of this appendix for the 2008 Resource Adequacy Compliance Year. Section 40 of this appendix shall apply to all other Load Serving Entities and their respective Scheduling Coordinators. For purposes of Section 40 of this appendix, a Load Serving Entity shall not include any entity satisfying the terms of California Public Utilities Code Section 380(j)(3).

40.1.1 Election of Load Serving Entity Status.

By December 18, 2007, via e-mail to reliabilityrequirements@caiso.com, the Scheduling Coordinator for a Load Serving Entity, not exempt under Section 40.1 of this appendix, shall inform the CAISO whether each such LSE elects to be either: (i) a Reserve Sharing LSE or (ii) a Modified Reserve Sharing LSE for the 2008 Resource Adequacy Compliance Year. A Scheduling Coordinator for a Load-following MSS is not required to make an election under this Section. Scheduling Coordinators for Load-following MSSs are subject solely to Sections 40.2.4 and 40.3 of this appendix.

The CAISO may confirm with the CPUC, Local Regulatory Authority, or federal agency, as applicable, the accuracy of the election by the Scheduling Coordinator for any LSE under its respective jurisdiction, or, in the absence of any election by the Scheduling Coordinator, the desired election for any LSE under its jurisdiction. The determination of the CPUC, Local Regulatory Authority, or federal agency will be deemed binding by the CAISO on the Scheduling Coordinator and the LSE. If the Scheduling Coordinator and CPUC, Local Regulatory Authority, or federal agency, as appropriate, fails to make the election on behalf of an LSE in accordance with the Business Practice Manual, the LSE shall be deemed a Reserve Sharing LSE.

40.2 Information Requirements Regarding Resource Adequacy Programs.

40.2.1. Reserve Sharing LSEs.

40.2.1.1 Requirements for CPUC Load Serving Entities Electing Reserve Sharing LSE Status.

The information required by Section 40.2.1.1 of this appendix shall be provided to the CAISO as follows:

- (a) The Scheduling Coordinator for a CPUC Load Serving Entity electing Reserve Sharing LSE status must provide the CAISO with all information or data to be provided to the CAISO as required by the CPUC and pursuant to the schedule adopted by the CPUC.
- (b) Where the information or data provided to the CAISO under Section 40.2.1.1(a) of this appendix does not include Reserve Margin(s), then the provisions of Section 40.2.2.1(b) of this appendix shall apply.
- (c) Where the information or data provided to the CAISO under Section 40.2.1.1(a) of this appendix does not include criteria for determining qualifying resource types and their Qualifying Capacity, then the provisions of Section 40.8 of this appendix shall apply.
- (d) Where the information or data provided to the CAISO under Section 40.2.1.1(a) of this appendix does not include annual and monthly Demand Forecast requirements, then the provisions of Section 40.2.2.3 of this appendix shall apply.
- (e) Where the information or data provided to the CAISO under Section 40.2.1.1(a) of this appendix does not include annual and monthly Resource Adequacy Plan requirements, then Section 40.2.2.4 of this appendix shall apply.

40.2.2 Requirements for Non-CPUC Load Serving Entities Electing Reserve Sharing LSE Status, Including Default Provisions for CPUC Load Serving Entities.

40.2.2.1 Reserve Margin.

The information required by Section 40.2.2.1 of this appendix shall be provided to the CAISO pursuant to the instructions set forth in a CAISO Market Notice within five (5) Business Days of the CAISO filing its statement certifying market readiness in accordance with Paragraph 1414 of 116 FERC ¶61,274 (2006).

- (a) The Scheduling Coordinator for a Non-CPUC Load Serving Entity electing Reserve Sharing LSE status must provide the CAISO with the Reserve Margin(s) adopted by the appropriate Local Regulatory Authority or federal agency for use in the annual Resource Adequacy Plan and monthly Resource Adequacy Plans listed as a percentage of the Demand Forecasts developed in accordance with Section 40.2.2.3 of this appendix.
- (b) For the Scheduling Coordinator for a Non-CPUC Load Serving Entity for which the appropriate Local Regulatory Authority or federal agency has not established a Reserve Margin(s) or a CPUC Load Serving Entity subject to Section 40.2.1.1(b) of this appendix that has elected Reserve Sharing LSE status, the Reserve Margin for each month shall be no less than 15% of the LSE's peak hourly Demand for the applicable month, as determined by the Demand Forecasts developed in accordance with Section 40.2.2.3 of this appendix.

40.2.2.2 Qualifying Capacity Criteria.

The information required by Section 40.2.2.2 of this appendix shall be provided to the CAISO pursuant to the instructions set forth in a CAISO Market Notice within five (5) Business Days of the CAISO filing its statement certifying market readiness in accordance with Paragraph 1414 of 116 FERC ¶61,274 (2006).

The Scheduling Coordinator for a Non-CPUC Load Serving Entity electing Reserve Sharing LSE status must provide the CAISO with a description of the criteria adopted by the Local Regulatory Authority or federal agency for determining qualifying resource types and the Qualifying Capacity from such resources and any modifications thereto as they are implemented from time to time. The Reserve Sharing LSE may elect to utilize the criteria set forth in Section 40.8 of this appendix.

40.2.2.3 Demand Forecasts.

The information required by Section 40.2.2.3 of this appendix shall be provided to the CAISO pursuant to the instructions set forth in a CAISO Market Notice within five (5) Business Days of the CAISO filing its statement certifying market readiness in accordance with Paragraph 1414 of 116 FERC ¶¶61,274 (2006).

The Scheduling Coordinator for a Non-CPUC Load Serving Entity or CPUC Load Serving Entity subject to Section 40.2.1.1(b) of this appendix electing Reserve Sharing LSE status must provide annual and monthly Demand Forecasts as part of the annual and monthly Resource Adequacy Plans under this appendix. The annual and monthly Demand Forecasts shall utilize the annual and monthly coincident peak Demand determinations provided by the California Energy Commission for such Load Serving Entity, which will be calculated from the Demand Forecast information submitted to the California Energy Commission by each Reserve Sharing LSE; or (ii) if the California Energy Commission does not produce coincident peak Demand Forecasts for the Load Serving Entity, the annual and monthly coincident peak Demand Forecasts produced by the CAISO for such Load Serving Entity in accordance with its Business Practice Manual. Scheduling Coordinators must provide data and information, as may be requested by the CAISO, necessary to develop or support the Demand Forecasts required by this Section.

40.2.2.4 Annual and Monthly Resource Adequacy Plans.

The Scheduling Coordinator for a Non-CPUC Load Serving Entity or a CPUC Load Serving Entity subject to Section 40.2.1.1(b) electing Reserve Sharing LSE status must provide annual and monthly Resource Adequacy Plans for such Load Serving Entity. For 2008 Resource Adequacy Compliance Year, the annual Resource Adequacy Plan shall be submitted to the CAISO on January 31, 2008 in the form set forth on the CAISO Website. The initial monthly Resource Adequacy Plan under this appendix shall be submitted to the CAISO on the first Business Day after 30 calendar days from the date the CAISO files its statement certifying market readiness in accordance with Paragraph 1414 of 116 FERC ¶61,274 (2006) in the form set forth on the CAISO Website. Thereafter, monthly Resource Adequacy Plans shall be submitted to the CAISO by the last Business Day of the second month prior to the compliance month and in the form set forth on the CAISO Website. Prior to the requirement to submit monthly Resource Adequacy Plans to the CAISO in accordance with Section 40.2.2.4 of this appendix, monthly Resource Adequacy Plans must continue to be submitted in accordance with Section 40.2.2 of the ISO Tariff. The annual Resource Adequacy Plan must, at a minimum, set forth the Local Capacity Area Resources, if any, procured by the Load Serving Entity as described in Section 40.3 of this appendix. The monthly Resource Adequacy Plan should identify all resources, including Local Capacity Area Resources, the Load Serving Entity will rely upon to satisfy the applicable month's peak hour Demand of the Load Serving Entity as determined by the Demand Forecasts developed in accordance with Section 40.2.2.3 of this appendix and applicable Reserve Margin. Resource Adequacy Plans must utilize the Net Qualifying Capacity requirements of Section 40.5.2 of the ISO Tariff.

40.2.3 Modified Reserve Sharing LSEs.

40.2.3.1 Reserve Margin.

The information required by Section 40.2.3.1 of this appendix shall be provided to the CAISO within five (5) Business Days of the CAISO filing its statement certifying market readiness in accordance with Paragraph 1414 of 116 FERC ¶61,274 (2006).

- (a) The Scheduling Coordinator for a Load Serving Entity electing Modified Reserve Sharing LSE status must provide the CAISO with the Reserve Margin(s) adopted by the CPUC, Local Regulatory Authority, or federal agency, as appropriate, for use in the annual Resource Adequacy Plan and monthly Resource Adequacy Plans listed as a percentage of the Demand Forecasts developed in accordance with Section 40.2.3.3 of this appendix.
- (b) For the Scheduling Coordinator for a Load Serving Entity electing Modified Reserve Sharing LSE status for which the CPUC, Local Regulatory Authority, or federal agency, as appropriate, has not established a Reserve Margin, the Reserve Margin shall be no less than fifteen percent (15%) of the applicable month's peak hour Demand of the Load Serving Entity, as determined by the Demand Forecasts developed in accordance with Section 40.2.3.3 of this appendix.

40.2.3.2 Qualifying Capacity.

The information required by Section 40.2.3.2 of this appendix shall be provided to the CAISO pursuant to the instructions set forth in a CAISO Market Notice within five (5) Business Days of the CAISO filing its statement certifying market readiness in accordance with Paragraph 1414 of 116 FERC ¶61,274 (2006).

The Scheduling Coordinator for a Load Serving Entity electing Modified Reserve Sharing LSE status must provide the CAISO with a description of the criteria for determining qualifying resource types and the Qualifying Capacity from such resources and any modifications thereto as they are implemented from time to time. The Modified Reserve Sharing LSE may elect to utilize the criteria set forth in Section 40.8 of this appendix.

40.2.3.3 Demand Forecasts.

- (a) The Scheduling Coordinator for a Load Serving Entity electing Modified Reserve Sharing LSE status must provide annual and monthly Demand Forecasts as part of the annual and monthly Resource Adequacy Plans under this appendix. The annual and monthly Demand Forecasts shall utilize the annual and monthly coincident peak Demand determinations provided by the California Energy Commission for such Load Serving Entity, which will be calculated from Demand Forecast data submitted to the California Energy Commission by each Modified Reserve Sharing LSE; or (ii) if the California Energy Commission does not produce coincident peak Demand Forecasts for the Load Serving Entity, the annual and monthly coincident peak Demand Forecasts produced by the CAISO for such Load Serving Entity. Scheduling Coordinators must provide data and information, as may be requested by the CAISO, to develop or support the Demand Forecast required by this Section 40.2.3.3 of this appendix.

40.2.3.4 Annual and Monthly Resource Adequacy Plans.

The Scheduling Coordinator for a Load Serving Entity electing Modified Reserve Sharing LSE status must provide annual and monthly Resource Adequacy Plans. For 2008 Resource Adequacy Compliance Year, the annual Resource Adequacy Plan shall be submitted to the CAISO on January 31, 2008 in the form set forth on the CAISO Website. The monthly Resource Adequacy Plan shall be submitted to the CAISO on the first Business Day after 30 calendar days from the date the CAISO files its statement certifying market readiness in accordance with Paragraph 1414 of 116 FERC ¶61,274 (2006) in the form set forth on the CAISO Website. Thereafter, monthly Resource Adequacy Plans shall be submitted to the CAISO by the last Business Day of the second month prior to the compliance month and in the form set forth on the CAISO Website for each Modified Reserve Sharing LSE served by the Scheduling Coordinator. Prior to the requirement to submit monthly Resource Adequacy Plans to the CAISO in accordance with Section 40.2.3.4 of this appendix, monthly Resource Adequacy Plans must continue to be submitted in

accordance with Section 40.2.2 of the ISO Tariff. The annual Resource Adequacy Plan must, at a minimum, set forth the Local Capacity Area Resources, if any, procured by the Modified Reserve Sharing LSE as described in Section 40.3 of this appendix. The monthly Resource Adequacy Plan must identify the resources the Modified Reserve Sharing LSE will rely upon to satisfy its forecasted monthly Demand and Reserve Margin as set forth in Section 40.2.3.1 of this appendix, for the relevant reporting period and must utilize the Net Qualifying Capacity requirements of Section 40.5.2 of the ISO Tariff.

40.2.4 Load-Following MSS.

A Scheduling Coordinator for a Load-following MSS must provide an annual Resource Adequacy Plan on January 31, 2008 for 2008 Resource Adequacy Compliance Year that sets forth, at a minimum, the Local Capacity Area Resources, if any, procured by the Load-following MSS as described in Section 40.3 of this appendix. The annual Resource Adequacy Plan shall utilize the annual coincident peak Demand determination provided by the California Energy Commission for such Load-following MSS using Demand Forecast data submitted to the California Energy Commission by the Load-following MSS, or, if the California Energy Commission does not produce coincident peak Demand Forecasts for the Load-following MSS, the annual coincident peak Demand Forecast produced by the CAISO for such Load-following MSS in accordance with its Business Practice Manual using Demand Forecast data submitted to the CAISO by the Load-following MSS.

**40.3 Local Capacity Area Resource Requirements Applicable to Scheduling
Coordinators for All Load Serving Entities.**

40.3.1 Local Capacity Technical Study.

For 2008 Resource Adequacy Compliance Year, the CAISO's 2008 Local Capacity Technical Analysis, dated April 3, 2007, located at <http://www.aiso.com/1bb5/1bb5ed3d46430.pdf> on the CAISO Website shall constitute the Local Capacity Technical Study for purposes of Section 40 of this appendix. For the 2009 Resource Adequacy Compliance Year, on an annual basis, pursuant to the schedule set forth in the Business Practice Manual, the CAISO will, perform, and publish on the CAISO Website the Local Capacity Technical Study. The Local Capacity Technical Study shall identify Local Capacity Areas, determine the minimum amount of Local Capacity Area Resources in MW that must be available to the CAISO within each identified Local Capacity Area, and identify the Generating Units within each identified Local Capacity Area. The CAISO shall collaborate with the CPUC, Local Regulatory Authorities within the CAISO Control Area, federal agencies, and Market Participants to ensure that the Local Capacity Technical Study is performed in accordance with this Section 40.3 and to establish for inclusion in the Business Practice Manual other parameters and assumptions applicable to the Local Capacity Technical Study and a schedule that provides for: (i) reasonable time for review of a draft Local Capacity Technical Study, (ii) reasonable time for Participating TOs to propose operating solutions, and (iii) release of the final Local Capacity Technical Study no later than 120 days prior to the date annual Resource Adequacy Plans must be submitted.

40.3.1.1 Local Capacity Technical Study Criteria.

The Local Capacity Technical Study will determine the minimum amount of Local Capacity Area Resources needed to address the Contingencies identified in Section 40.3.1.2 of this appendix. In performing the Local Capacity Technical Study, the CAISO will apply those methods for resolving Contingencies considered appropriate for the performance level that corresponds to a particular studied Contingency, as provided in NERC Reliability Standards TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0, as augmented by CAISO Reliability Criteria in accordance with the Transmission Control Agreement and Section 24.2.1 of Appendix EE. The CAISO Reliability Criteria shall include:

- (1) Time Allowed for Manual Readjustment: This is the amount of time required for the operator to take all actions necessary to prepare the system for the next contingency. This time should not be less than 30 minutes.
- (2) No voltage collapse or dynamic instability shall be allowed for the Category D event-any B1-4 system readjusted (Common Mode) L-2, as listed in Section 40.3.1.2.

40.3.1.2 Local Capacity Technical Study Contingencies.

The Local Capacity Technical Study shall assess the following Contingencies:

Contingency Component(s)
NERC/WECC Performance Level A – No Contingencies
NERC/WECC Performance Level B – Loss of a single element
1. Generator (G-1) 2. Transmission Circuit (L-1) 3. Transformer (T-1) 4. Single Pole (dc) Line 5. G-1 system readjusted L-1
NERC/WECC Performance Level C – Loss of two or more elements
3. L-1 system readjusted G-1 3. G-1 system readjusted T-1 or T-1 system readjusted G-1 3. L-1 system readjusted T-1 or T-1 system readjusted L-1 3. G-1 system readjusted G-1 3. L-1 system readjusted L-1 4. Bipolar (dc) Line 5. Two circuits (Common Mode) L-2 9. SLG fault (stuck breaker or protection failure) for Bus section WECC-S3. Two generators (Common Mode) G-2
D – Extreme event – loss of two or more elements
Any B1-4 system readjusted (Common Mode) L-2 All other extreme combinations D1-14.

40.3.2 Allocation of Local Capacity Area Resource Obligations.

The CAISO will allocate responsibility for Local Capacity Area Resources to Scheduling Coordinators for Load Serving Entities in the following sequential manner:

- (a) The responsibility for the aggregate Local Capacity Area Resources required for all Local Capacity Areas within each TAC Area as determined by the Local Capacity Technical Study will be allocated to all Scheduling Coordinators for Load Serving Entities that serve Load in the TAC Area in accordance with the Load Serving Entity's proportionate share of the LSE's TAC Area Load at the time of the CAISO's annual coincident peak Demand set forth in the annual peak Demand Forecast for the next Resource Adequacy Compliance Year as determined by the California Energy Commission. Expressed as a formula, the allocation of Local Area Capacity Resource obligations will be as follows: $(\sum \text{Local Capacity Area MW in TAC Area from the Local Capacity Technical Study}) * (\text{LSE Demand in TAC Area at CAISO annual coincident peak Demand}) / (\text{Total TAC Area Demand at the time of CAISO annual coincident peak Demand})$. This will result in a MW responsibility for each Load Serving Entity for each TAC Area in which the LSE serves Load. The LSE may meet its MW responsibility, as assigned under this Section, for each TAC Area in which the LSE serves Load by procurement of that MW quantity in any Local Capacity Area in the TAC Area.
- (b) For Scheduling Coordinators for Non-CPUC Load Serving Entities, the Local Capacity Area Resource obligation will be allocated based on Section 40.3.2(a) of this appendix.
- (c) For Scheduling Coordinators for CPUC Load Serving Entities, the CAISO will allocate the Local Capacity Area Resource obligation based on an allocation methodology, if any, adopted by the CPUC. However, if the allocation methodology adopted by the CPUC does not fully allocate the total sum of each CPUC Load Serving Entity's proportionate share calculated under Section 40.3.2(a) of this appendix, the CAISO will allocate the difference to all Scheduling Coordinators for CPUC Load Serving Entities in accordance with their proportionate share calculated under 40.3.2(a) of this

appendix. If the CPUC does not adopt an allocation methodology, the CAISO will allocate Local Capacity Area Resources to Scheduling Coordinators for CPUC Load Serving Entities based on Section 40.3.2(a) of this appendix.

Once the CAISO has allocated the total responsibility for Local Capacity Area Resources, the CAISO will inform the Scheduling Coordinator for each LSE of the LSE's specific allocated responsibility for Local Capacity Area Resources in each TAC Area in which the LSE serves Load.

40.3.3 Procurement of Local Capacity Area Resource Obligations by Load Serving Entities.

Nothing in Section 40 of this appendix obligates a Load Serving Entity to procure Local Capacity Area Resources to satisfy capacity requirements for each Local Capacity Area identified in the Local Capacity Technical Study. Scheduling Coordinators for Load Serving Entities may aggregate responsibilities for procurement of Local Capacity Area Resources. If a Load Serving Entity has procured Local Capacity Area Resources that satisfy generation capacity requirements for Local Capacity Areas, the Scheduling Coordinator for such Load Serving Entity shall include this information in its annual and monthly Resource Adequacy Plan(s).

40.4.7 Submission of Supply Plans.

(a) Scheduling Coordinators representing Resource Adequacy Resources supplying Resource Adequacy Capacity shall provide the CAISO with annual and monthly Supply Plans verifying their agreement to provide Resource Adequacy Capacity during the 2008 Resource Adequacy Compliance Year or relevant month, as applicable. For 2008 Resource Adequacy Compliance Year, an annual Supply Plan or certification that a previously submitted annual Supply Plan for 2008 Resource Adequacy Compliance Year has not changed shall be submitted to the CAISO on January 31, 2008 in the form set forth on the CAISO Website, and the initial monthly Supply Plan shall be submitted to the CAISO on the first Business Day after 30 calendar days from the date the CAISO files its statement certifying market readiness in accordance with Paragraph 1414 of 116 FERC ¶61,274 (2006). Thereafter, Supply Plans shall be submitted to the CAISO by the last Business Day of the second month prior to the compliance month. Prior to the requirement to submit Supply Plans to the CAISO in accordance with Section 40.4.7 of this appendix, monthly Supply Plans must be submitted in accordance with Section 40.6 of the ISO Tariff.

(b) The Supply Plan must be in the form of the template provided on the CAISO Website, which shall include an affirmative representation by the Scheduling Coordinator submitting the Supply Plan that the CAISO is entitled to rely on the accuracy of the information provided in the Supply Plan.

(c) The CAISO shall be entitled to take reasonable measures to validate the accuracy of the information submitted in Supply Plans under this Section of the appendix, including;

(1) Comparing a Resource Adequacy Resource's Resource Adequacy Capacity against the Resource Adequacy Resource's Net Qualifying Capacity, if applicable. To the extent the Resource Adequacy Capacity of a Resource Adequacy Resource included in a Supply Plan is greater than the Resource Adequacy Resource's Net Qualifying Capacity, the CAISO will notify the respective Scheduling Coordinators for the Resource Adequacy Resource and each Load Serving Entity that has included the Resource Adequacy Resource on its Resource Adequacy Plan that the Resource Adequacy Capacity

from the Resource Adequacy Resource shall be reduced to the Resource Adequacy Resource's Net Qualifying Capacity and that it will be considered a mismatch under Section 40.7 of this appendix. If the CAISO is not advised as to how the reduction in Resource Adequacy Capacity to conform with the Resource Adequacy Resource's Net Qualifying Capacity shall be allocated among each Load Serving Entity that included the Resource Adequacy Resource on its Resource Adequacy Plan, the CAISO will apply a pro rata reduction based on the Supply Plan.

- (a) Disputes regarding the CAISO's determination of Net Qualifying Capacity shall be subject to Section 40.5.2 of the CAISO Tariff.
 - (b) The provisions of this Section shall not affect a Resource Adequacy Resource's Net Qualifying Capacity posted by the CAISO under Section 40.5.2 of the CAISO Tariff.
- (2) Other errors or inaccuracies identified by the CAISO in a Supply Plan shall be treated as a mismatch under Section 40.7 of this appendix.

40.6.4 Additional Availability Requirements for Use-Limited Resources.

40.6.4.1 Registration of Use-Limited Resources.

Scheduling Coordinators for Use-Limited Resources, other than for hydroelectric Generating Units and Participating Load, including Pumping Load, must provide the CAISO an application in the form specified on the CAISO Website requesting registration of a specifically identified resource as a Use-Limited Resource. For any Use-Limited Resource that anticipates being included in an annual or monthly Resource Adequacy Plan and/or Supply Plan under this appendix, the registration shall be submitted by January 7, 2008. This application shall include specific operating data and supporting documentation including, but not limited to;

- 1) a detailed explanation of why the resource is subject to operating limitations;
- 2) historical data to show attainable MWhs for each 24-hour period during the preceding year, including, as applicable, environmental restrictions for NO_x, SO_x, or other factors; and
- 3) further data or other information as may be requested by the CAISO to understand the operating characteristics of the unit.

Within fifteen (15) Business Days after receipt of the application, the CAISO will respond to the Scheduling Coordinator as to whether or not the CAISO agrees that the facility is eligible to be a Use-Limited Resource. If the CAISO determines the facility is not a Use-Limited Resource, the Scheduling Coordinator may challenge that determination in accordance with the CAISO ADR Procedures.

40.6.4.2 Use Plan.

The Scheduling Coordinator shall provide for the 2008 Resource Adequacy Compliance Year a proposed annual use plan for each Use-Limited Resource that is a Resource Adequacy Resource. The proposed annual use plan will delineate on a month-by-month basis the total MWhs of Generation, total run hours, expected daily supply capability (if greater than four hours) and the daily Energy limit, operating constraints, and the timeframe for each constraint. The CAISO will have an opportunity to discuss the proposed annual use plan with the Scheduling Coordinator and suggest potential revisions to meet reliability needs of the system. The Scheduling Coordinator shall then submit its final annual use plan. Scheduling Coordinators for Use-Limited Resources must submit the proposed and final annual use plans in accordance with the schedule set forth in the Business Practice Manual. The Scheduling Coordinator will be able to update the projections made in the annual use plan in the monthly Resource Adequacy Plans. Hydroelectric Generating Units and Pumping Load will be able to update use plans intra-monthly as necessary to reflect evolving hydrological and meteorological conditions. The annual use plan must reflect the potential operation of the Use-Limited Resource at a level no less than the minimum criteria set forth by the Local Regulatory Authority for qualification of the resource.

40.7 Compliance.

The CAISO will evaluate whether each annual and monthly Resource Adequacy Plan submitted by a Scheduling Coordinator on behalf of a Load Serving Entity under this appendix (including for 2008 each monthly Resource Adequacy Plan submitted pursuant to Sections 40.2.2 of the CAISO Tariff) demonstrates Resource Adequacy Capacity sufficient to satisfy the Load Serving Entity's (i) allocated responsibility for Local Capacity Area Resources under Section 40.3.2 of this appendix and (ii) applicable Demand and Reserve Margin requirements. In the case of an annual Reserve Margin requirement for 2008, the CAISO will also evaluate the annual Resource Adequacy Plan submitted under Section 40.2.1. If the CAISO determines that a Resource Adequacy Plan does not demonstrate Local Capacity Area Resources sufficient to meet its allocated responsibility under Section 40.3.2 of this appendix, compliance with applicable Demand and Reserve Margin requirements, or compliance with any other resource adequacy requirement in this appendix or adopted by the CPUC, Local Regulatory

Authority, or federal agency, as applicable, the CAISO will notify the relevant Scheduling Coordinator, CPUC, Local Regulatory Authority, or federal agency with jurisdiction over the relevant Load Serving Entity, 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 any deficiency. The notification will include the reasons the CAISO believes a deficiency exists. If the deficiency relates to the demonstration of Local Capacity Area Resources in a Load Serving Entity's annual Resource Adequacy Plan, and the CAISO does not provide a written notice of resolution of the deficiency, the Scheduling Coordinator for the Load Serving Entity may demonstrate that the identified deficiency is cured by submitting a revised annual Resource Adequacy Plan within sixty (60) days after the annual Resource Adequacy Plan is due under Sections 40.2.3.4, 40.2.2.4 and 40.2.4 of this appendix. For all other identified deficiencies, at least ten (10) days prior the effective month of the relevant Resource Adequacy Plan, the Scheduling Coordinator for the Load Serving Entity shall (i) demonstrate that the identified deficiency is cured by submitting a revised Resource Adequacy Plan or (ii) advise the CAISO that the CPUC, Local Regulatory Authority, or federal agency, as appropriate, has determined that no deficiency exists. In the case of a mismatch between Resource Adequacy Plan(s) and Supply Plan(s), if resolved, the relevant Scheduling Coordinator(s) must provide the CAISO with revised Resource Adequacy Plan(s) or Supply Plans, as applicable, at least ten (10) days prior to the effective month. If the CAISO is not advised that the deficiency or mismatch is resolved at least ten (10) days prior to the effective month, the CAISO will use the information contained in the Supply Plan to set the obligations of Resource Adequacy Resources under Section 40 of this appendix.

40.8 CAISO Default Qualifying Capacity Criteria.

40.8.1 Applicability.

The criteria in Section 40.8 of this appendix shall apply only: (i) where the CPUC or Local Regulatory Authority has not established and provided to the CAISO 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 and (ii) until the CAISO has been notified in writing by the CPUC of its intent to overturn, reject or fundamentally modify the capacity-based framework in CPUC Decisions 04-01-050 (Jan. 10, 2004), 04-10-035 (Oct. 28, 2004), and 05-10-042 (Oct. 31, 2005). The types of resources specified in Section 40.8.1 of this appendix will be eligible to provide Qualifying Capacity to the extent they meet the criteria for each type of resource set forth in Section 40.8.1 of this appendix.

40.8.1.2 Nuclear and Thermal.

Nuclear and thermal Generating Units, other than Qualifying Facilities with effective contracts under the Public Utility Regulatory Policies Act addressed in Section 40.8.1.8 of this appendix 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 40.8.1.8 of this appendix, will be based on net dependable capacity defined by NERC Generating Availability Data System information.

40.8.1.3 Hydro.

Hydroelectric Generating Units, other than Qualifying Facilities 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 derate 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 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 Qualifying Facilities, will be based on net dependable capacity defined by NERC GADS minus an average dry year conveyance flow, stream flow, or canal head derate. 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).

40.8.1.4 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.

40.8.1.5 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 CAISO 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 25% of its portfolio of Qualifying Capacity met by contracts with liquidated damage provisions for 2008.

40.8.1.6 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 Qualifying Facilities with effective contracts under the Public Utility Regulatory Policies Act, must be Participating Intermittent Resources or subject to availability provisions of Section 40.6.4.3.4 upon that section's effective date.

The Qualifying Capacity of all wind or solar units, including Qualifying Facilities, for each month will be based on their monthly historic performance during that same month during the hours of noon to 6:00 p.m., using a three-year rolling average. For wind or solar units with less than three years operating history, all months for which there is no historic performance data will utilize the monthly average production factor of all units (wind or solar, as applicable) within the TAC Area in which the Generating Unit is located.

40.8.1.7 Geothermal.

Geothermal Generating Units, other than Qualifying Facilities addressed in Section 40.8.1.8 of this appendix, must be Participating Generators or System Units. The Qualifying Capacity of geothermal units, other than Qualifying Facilities addressed in Section 40.8.1.8 of this appendix, will be based on NERC GADS net dependable capacity minus a derate for steam field degradation.

40.8.1.8 Treatment of Qualifying Capacity for Qualifying Facilities.

Qualifying Facilities must be subject to an effective Participating Generator Agreement or QF Participating Generator Agreement or must be System Units, unless they have a PURPA contract. Except for hydro, wind, and solar Qualifying Facilities addressed pursuant to Sections 40.8.1.3 and 40.8.1.6 of this appendix, the Qualifying Capacity of Qualifying Facilities under PURPA contracts, will be based on historic monthly Generation output during the hours of noon to 6:00 p.m. (net of Self-provided Load) during a three-year rolling average.

40.8.1.9 Participating Loads.

The Qualifying Capacity of Participating Loads shall be the average reduction in Demand 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 Loads must be available at least 48 hours, and if the Participating Loads can only be dispatched for a maximum of two hours per event, then only 0.89 percent of a Scheduling Coordinator's portfolio may be made up of such Loads.

40.8.1.10 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 40.8.1 of this appendix. In addition, the Scheduling Coordinator must provide the CAISO 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.

40.8.1.11 Facilities under Construction.

The Qualifying Capacity for facilities under construction will be determined based on the type of resource as described elsewhere in Section 40.8 of this appendix. 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 Resource Adequacy Plan.

40.8.1.12 System Resources.

40.8.1.12.1 Dynamic System Resources.

Dynamic System Resources shall be treated similar to resources within the CAISO Control Area, except with respect to the deliverability screen under Section 40.5.2.1 of the CAISO Tariff. However, eligibility as a Resource Adequacy Resource is contingent upon a showing by the Scheduling Coordinator that the Dynamic 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 for which the Scheduling Coordinator is submitting Demand Bids has an allocation of import capacity at the import Scheduling Point under Section 40.5.2.2 of the CAISO Tariff that is not less than the Resource Adequacy Capacity provided by the Dynamic System Resource.

40.8.1.12.2 Non-Dynamic System Resources.

For Non-Dynamic System Resources, the Scheduling Coordinator must demonstrate that the Load Serving Entity for 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 CAISO Tariff that is not less than the Resource Adequacy Capacity from the Non-Dynamic System Resource. The Scheduling Coordinator must also demonstrate that the Non-Dynamic System Resource is covered by Operating Reserves, unless unit contingent, in the sending Control Area. Eligibility as Resource Adequacy Capacity is 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-Dynamic 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.

PART B - DEFINITIONS

Unless defined in this Appendix CC or the context otherwise requires, all capitalized terms and expressions used in this Appendix CC shall have the meaning as defined in the Master Definitions Supplement in Appendix A. The following capitalized terms and expressions used in this Appendix CC shall have the meanings set forth below unless otherwise stated or the context otherwise requires. If two or more capitalized terms are used together in a manner not uniquely defined in Appendix A or this Appendix CC, the meanings of each defined term apply.

- CPUC Load Serving Entity** Any entity serving retail Load in the CAISO Control Area under the jurisdiction of the CPUC, including an electrical corporation under section 218 of the California Public Utilities Code, an electric service provider under section 218.3 of the California Public Utilities Code, and a community choice aggregator under section 331.1 of the California Public Utilities Code.
- Dynamic Resource-Specific System Resource** A Dynamic System Resource that is a specific generation resource outside the CAISO Control Area.
- Firm Liquidated Damages Contract** A contract utilizing or consistent with Service Schedule C of the Western Systems Power Pool Agreement or the Firm Liquidated Damages 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 CAISO Control Area.
- 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, that (a) (i) serves End Users within the CAISO Control Area and (ii) 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 CAISO Control Area; (b) is a federal power marketing authority that serves End Users; or (c) is the State Water Resources Development System commonly known as the State Water Project of the California Department of Water Resources.

Local Capacity Area	Transmission constrained area as defined in the study referenced in Section 40.3.1 of Appendix CC.
Local Capacity Area Resources	Resource Adequacy Capacity from a Generating Unit listed in the technical study or Participating Load that is located within a Local Capacity Area capable of contributing toward the amount of capacity required in a particular Local Capacity Area.
Local Capacity Technical Study	The study performed by the CAISO pursuant to Section 40.3.
Modified Reserve Sharing LSE	A Load Serving Entity whose Scheduling Coordinator has informed the CAISO in accordance with Section 40.1 of its election to be a Modified Reserve Sharing LSE.
Non-CPUC Load Serving Entity	Any entity serving retail Demand in the CAISO Control Area not within the jurisdiction of the CPUC, including (i) a local publicly owned electric utility under section 9604 of the California Public Utilities Code and (ii) any federal entities, including but not limited to federal power marketing authorities, that serve retail Load.
Non-Dynamic Resource-Specific System Resource	A Non-Dynamic System Resource that is a specific generation resource outside the CAISO Control Area.
Pumped-Storage Hydro Unit	A hydroelectric dam with the capability to produce electricity and the ability to pump water between reservoirs at different elevations to store such water for the production of electricity.
Pumping Load	A hydro pumping resource that is capable of responding to Dispatch Instructions by ceasing to pump.
Reserve Margin	The amount of Resource Adequacy Capacity that a Scheduling Coordinator is required to maintain in accordance with Section 40.
Reserve Sharing LSE	A Load Serving Entity whose Scheduling Coordinator has informed the CAISO in accordance with Section 40.1 of its election to be a Reserve Sharing LSE.
Resource Adequacy Compliance Year	A calendar year from January 1 through December 31.
Resource-Specific System Resource	A Dynamic or Non-Dynamic Resource-Specific System Resource.
Use-Limited Resource	A resource that, due to design considerations, environmental restrictions on operations, cyclical requirements, such as the need to recharge or refill, or other non-economic reasons, is unable to operate continuously on a daily basis, but is able to operate for a minimum set of consecutive Trading Hours each Trading Day.

ISO TARIFF APPENDIX DD
SMALL GENERATOR
INTERCONNECTION AGREEMENT (SGIA)

**SMALL GENERATOR
INTERCONNECTION AGREEMENT (SGIA)**

(For Generating Facilities No Larger Than 20 MW)

Small Generator Interconnection Agreement

This Small Generator Interconnection Agreement ("Agreement") is made and entered into this _____ day of _____, 20__, by _____ ("Participating TO"), the California Independent System Operator Corporation, a California nonprofit public benefit corporation organized and existing under the laws of the State of California ("ISO") and _____ ("Interconnection Customer") each hereinafter sometimes referred to individually as "Party" or referred to collectively as the "Parties."

Participating TO Information

Participating TO: _____
Attention: _____
Address: _____
City: _____ State: _____ Zip: _____
Phone: _____ Fax: _____

ISO Information

Attention: Phil Pettingill
151 Blue Ravine Road
Folsom, CA 95630
Phone: 916-351-4400 Fax: _____

Interconnection Customer Information

Interconnection Customer: _____
Attention: _____
Address: _____
City: _____ State: _____ Zip: _____
Phone: _____ Fax: _____

Interconnection Customer Application No: _____

In consideration of the mutual covenants set forth herein, the Parties agree as follows:

Article 1. Scope and Limitations of Agreement

- 1.1 This Agreement shall be used for all Interconnection Requests submitted under the Small Generator Interconnection Procedures (SGIP) **except for those submitted under the 10 kW Inverter Process contained in SGIP Attachment 5.**
- 1.2 This Agreement governs the terms and conditions under which the Interconnection Customer's Small Generating Facility will interconnect with, and operate in parallel with, the Participating TO's Transmission System.
- 1.3 This Agreement does not constitute an agreement to purchase or deliver the Interconnection Customer's power. The purchase or delivery of power and other services that the Interconnection Customer may require will be covered under separate agreements, if any. The Interconnection Customer will be responsible for separately making all necessary arrangements (including scheduling) for delivery of electricity in accordance with the ISO Tariff.
- 1.4 Nothing in this Agreement is intended to affect any other agreement between or among the Parties.

1.5 Responsibilities of the Parties

- 1.5.1 The Parties shall perform all obligations of this Agreement in accordance with all Applicable Laws and Regulations, Operating Requirements, and Good Utility Practice. The Parties shall use the Standard Large Generator Interconnection Agreement (ISO Tariff Appendix V) to interpret the responsibilities of the Parties under this Agreement.
- 1.5.2 The Interconnection Customer shall construct, interconnect, operate and maintain its Small Generating Facility and construct, operate, and maintain its Interconnection Facilities in accordance with the applicable manufacturer's recommended maintenance schedule, and in accordance with this Agreement, and with Good Utility Practice.
- 1.5.3 The Participating TO shall construct, operate, and maintain its Interconnection Facilities and Upgrades in accordance with this Agreement, and with Good Utility Practice. The ISO and the 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 Agreement.
- 1.5.4 The Interconnection Customer agrees to construct its facilities or systems in accordance with applicable specifications that meet or exceed those provided by the National Electrical Safety Code, the American National Standards Institute, IEEE, Underwriter's Laboratory, and Operating Requirements in effect at the time of construction and other applicable national and state codes and standards. The Interconnection Customer agrees to design, install, maintain, and operate its Small Generating Facility so as to reasonably minimize the likelihood of a disturbance adversely affecting or impairing the system or equipment of the Participating TO and any Affected Systems. The Interconnection Customer shall comply with the Participating TO's Interconnection Handbook. In the event of a conflict between the terms of this Agreement and the terms of the Participating TO's Interconnection Handbook, the terms in this Agreement shall govern.
- 1.5.5 Each Party shall operate, maintain, repair, and inspect, and shall be fully responsible for the facilities that it now or subsequently may own unless otherwise specified in the Attachments to this Agreement. Each Party shall be responsible for the safe installation, maintenance, repair and condition of their respective lines and appurtenances on their respective sides of the point of change of ownership. The Participating TO and the Interconnection Customer, as appropriate, shall provide Interconnection Facilities that adequately protect the ISO Controlled Grid, the Participating TO's electric system, the Participating TO's personnel, and other persons from damage and injury. The allocation of responsibility for the design, installation, operation, maintenance and ownership of Interconnection Facilities shall be delineated in the Attachments to this Agreement.
- 1.5.6 The Participating TO and the ISO shall coordinate with Affected Systems to support the interconnection.
- 1.5.7 The Interconnection Customer shall execute the Reliability Management System Agreement of the Western Electricity Coordinating Council prior to parallel operation of the Small Generating Facility. The Reliability Management System Agreement is provided as Attachment 8 to this Agreement.

1.6 Parallel Operation Obligations

Once the Small Generating Facility has been authorized to commence parallel operation, the Interconnection Customer shall abide by all rules and procedures pertaining to the parallel operation of the Small Generating Facility in the ISO Control Area, including, but not limited to; 1) the rules and procedures concerning the operation of generation set forth in the ISO Tariff for the ISO Controlled Grid and; 2) the Operating Requirements set forth in Attachment 5 of this Agreement.

1.7 Metering

The Interconnection Customer shall be responsible for the reasonable and necessary cost for the purchase, installation, operation, maintenance, testing, repair, and replacement of metering and data acquisition equipment specified in Attachments 2 and 3 of this Agreement. The Interconnection Customer's metering (and data acquisition, as required) equipment shall conform to applicable industry rules and Operating Requirements.

1.8 Reactive Power

1.8.1 The Interconnection Customer shall design its Small Generating Facility to maintain a composite power delivery at continuous rated power output at the terminals of each 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 similarly situated generators in the ISO Control Area on a comparable basis. The requirements of this paragraph shall not apply to wind generators and the requirements of Attachment 7 shall apply instead.

1.8.2 Payment to the Interconnection Customer for reactive power that the Small Generating Facility provides or absorbs when the ISO requests the Interconnection Customer to operate its Small Generating Facility outside the range specified in article 1.8.1 will be made by the ISO in accordance with the applicable provisions of the ISO Tariff.

1.9 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of this Agreement.

Article 2. Inspection, Testing, Authorization, and Right of Access

2.1 Equipment Testing and Inspection

2.1.1 The Interconnection Customer shall test and inspect its Small Generating Facility and Interconnection Facilities prior to interconnection. The Interconnection Customer shall notify the Participating TO and the ISO of such activities no fewer than five Business Days (or as may be agreed to by the Parties) prior to such testing and inspection. Testing and inspection shall occur on a Business Day. The Participating TO and the ISO may, at their own expense, send qualified personnel to the Small Generating Facility site to inspect the interconnection and observe the testing. The Interconnection Customer shall provide the Participating TO and the ISO a written test report when such testing and inspection is completed.

2.1.2 The Participating TO and the ISO shall provide the Interconnection Customer written acknowledgment that they have received the Interconnection Customer's written test report. Such written acknowledgment shall not be deemed to be or construed as any representation, assurance, guarantee, or warranty by the Participating TO or the ISO of the safety, durability, suitability, or reliability of the Small Generating Facility or any associated control, protective, and safety devices owned or controlled by the Interconnection Customer or the quality of power produced by the Small Generating Facility.

2.2 Authorization Required Prior to Parallel Operation

2.2.1 The Participating TO and the ISO shall use Reasonable Efforts to list applicable parallel operation requirements in Attachment 5 of this Agreement. Additionally, the Participating TO and the ISO shall notify the Interconnection Customer of any changes to these requirements as soon as they are known. The Participating TO and the ISO shall make Reasonable Efforts to cooperate with the Interconnection Customer in meeting requirements necessary for the Interconnection Customer to commence parallel operations by the in-service date.

2.2.2 The Interconnection Customer shall not operate its Small Generating Facility in parallel with the Participating TO's Transmission System without prior written authorization of the Participating TO. The Participating TO will provide such authorization to the Interconnection Customer and the ISO once the Participating TO receives notification that the Interconnection Customer has complied with all applicable parallel operation requirements. Such authorization shall not be unreasonably withheld, conditioned, or delayed.

2.3 Right of Access

2.3.1 Upon reasonable notice, the Participating TO and the ISO may send a qualified person to the premises of the Interconnection Customer at or immediately before the time the Small Generating Facility first produces energy to inspect the interconnection, and observe the commissioning of the Small Generating Facility (including any required testing), startup, and operation for a period of up to three Business Days after initial start-up of the unit. In addition, the Interconnection Customer shall notify the Participating TO and the ISO at least five Business Days prior to conducting any on-site verification testing of the Small Generating Facility.

2.3.2 Following the initial inspection process described above, at reasonable hours, and upon reasonable notice, or at any time without notice in the event of an emergency or hazardous condition, the Participating TO and the ISO shall have access to the Interconnection Customer's premises for any reasonable purpose in connection with the performance of the obligations imposed on it by this Agreement or if necessary to meet its legal obligation to provide service to its customers.

2.3.3 Each Party shall be responsible for its own costs associated with following this article.

Article 3. Effective Date, Term, Termination, and Disconnection

3.1 Effective Date

This Agreement shall become effective upon execution by the Parties subject to acceptance by FERC (if applicable), or if filed unexecuted, upon the date specified by the FERC. The Participating TO and the ISO shall promptly file this Agreement with the FERC upon execution, if required.

3.2 Term of Agreement

This Agreement shall become effective on the Effective Date and 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, unless terminated earlier in accordance with article 3.3 of this Agreement.

3.3 Termination

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 Agreement (if required), which notice has been accepted for filing by FERC.

3.3.1 The Interconnection Customer may terminate this Agreement at any time by giving the Participating TO and the ISO 20 Business Days written notice.

3.3.2 Any Party may terminate this Agreement after Default pursuant to article 7.6.

3.3.3 Upon termination of this Agreement, the Small Generating Facility will be disconnected from the ISO Controlled Grid. 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 Agreement or such non-terminating Party otherwise is responsible for these costs under this Agreement.

3.3.4 The termination of this Agreement shall not relieve any Party of its liabilities and obligations, owed or continuing at the time of termination.

3.3.5 The provisions of this article shall survive termination or expiration of this Agreement.

3.4 Temporary Disconnection

Temporary disconnection of the Small Generating Facility or associated Interconnection Facilities shall continue only for so long as reasonably necessary under Good Utility Practice.

3.4.1 Emergency Conditions

"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; (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, the 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 Small Generating Facility or the Interconnection Customer's Interconnection Facilities. Under Emergency Conditions, the ISO or the Participating TO may immediately suspend interconnection service and temporarily disconnect the Small Generating Facility. The Participating TO or the ISO shall notify the Interconnection Customer promptly when it becomes aware of an Emergency Condition that may reasonably be expected to affect the Interconnection Customer's operation of the Small 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 may reasonably be expected to affect the ISO Controlled Grid, the Participating TO's Interconnection Facilities, or any Affected Systems. 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 necessary corrective action.

3.4.2 Routine Maintenance, Construction, and Repair

The Participating TO or the ISO may interrupt interconnection service or curtail the output of the Small Generating Facility and temporarily disconnect the Small Generating Facility from the ISO Controlled Grid when necessary for routine maintenance, construction, and repairs on the ISO Controlled Grid or the Participating TO's electric system. The Party scheduling the interruption shall provide the Interconnection Customer with five Business Days notice prior to such interruption. The Party scheduling the interruption shall use Reasonable Efforts to coordinate such reduction or temporary disconnection with the Interconnection Customer.

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.

3.4.3 Forced Outages

During any forced outage, the Participating TO or the ISO may suspend interconnection service to effect immediate repairs on the ISO Controlled Grid or the Participating TO's electric system. The Participating TO or the ISO shall use Reasonable Efforts to provide the Interconnection Customer with prior notice. If prior notice is not given, the Participating TO or the ISO shall, upon request, provide the Interconnection Customer written documentation after the fact explaining the circumstances of the disconnection. The Interconnection Customer shall notify ISO, as soon as practicable, of all forced outages or reductions of the Small Generating Facility in accordance with the ISO Tariff.

3.4.4 Adverse Operating Effects

The Participating TO or the ISO shall notify the Interconnection Customer as soon as practicable if, based on Good Utility Practice, operation of the Small Generating Facility may cause disruption or deterioration of service to other customers served from the same electric system, or if operating the Small Generating Facility could cause damage to the ISO Controlled Grid, the Participating TO's Transmission System or Affected Systems. Supporting documentation used to reach the decision to disconnect shall be provided to the Interconnection Customer upon request. If, after notice, the Interconnection Customer fails to remedy the adverse operating effect within a reasonable time, the Participating TO or the ISO may disconnect the Small Generating Facility. The Participating TO or the ISO shall provide the Interconnection Customer with five Business Day notice of such disconnection, unless the provisions of article 3.4.1 apply.

3.4.5 Modification of the Small Generating Facility

The Interconnection Customer must receive written authorization from the Participating TO and the ISO before making any change to the Small Generating Facility that may have a material impact on the safety or reliability of the ISO Controlled Grid or the Participating TO's electric system. Such authorization shall not be unreasonably withheld. Modifications shall be done in accordance with Good Utility Practice. If the Interconnection Customer makes such modification without the Participating TO's and the ISO's prior written authorization, the Participating TO or the ISO shall have the right to temporarily disconnect the Small Generating Facility.

3.4.6 Reconnection

The Parties shall cooperate with each other to restore the Small Generating Facility, Interconnection Facilities, the Participating TO's electric system, and the ISO Controlled Grid to their normal operating state as soon as reasonably practicable following a temporary disconnection.

Article 4. Cost Responsibility for Interconnection Facilities and Distribution Upgrades

4.1 Interconnection Facilities

4.1.1 The Interconnection Customer shall pay for the cost of the Interconnection Facilities itemized in Attachment 2 of this Agreement. The Participating TO shall provide a best estimate cost, including overheads, for the purchase and construction of its Interconnection Facilities and provide a detailed itemization of such costs. Costs associated with Interconnection Facilities may be shared with other entities that may benefit from such facilities by agreement of the Interconnection Customer, such other entities, the ISO, and the Participating TO.

4.1.2 The Interconnection Customer shall be responsible for its share of all reasonable expenses, including overheads, associated with (1) owning, operating, maintaining, repairing, and replacing its own Interconnection Facilities, and (2) operating, maintaining, repairing, and replacing the Participating TO's Interconnection Facilities.

4.2 Distribution Upgrades

The Participating TO shall design, procure, construct, install, and own the Distribution Upgrades described in Attachment 6 of this Agreement. If the Participating TO and the Interconnection Customer agree, the Interconnection Customer may construct Distribution Upgrades that are located on land owned by the Interconnection Customer. The actual cost of the Distribution Upgrades, including overheads, shall be directly assigned to the Interconnection Customer.

Article 5. Cost Responsibility for Network Upgrades

5.1 Applicability

No portion of this article 5 shall apply unless the interconnection of the Small Generating Facility requires Network Upgrades.

5.2 Network Upgrades

The Participating TO shall design, procure, construct, install, and own the Network Upgrades described in Attachment 6 of this Agreement. If the Participating TO and the Interconnection Customer agree, the Interconnection Customer may construct Network Upgrades that are located on land owned by the Interconnection Customer. Unless the Participating TO elects to pay for Network Upgrades, the actual cost of the Network Upgrades, including overheads, shall be borne initially by the Interconnection Customer.

5.3 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 5.3.1.

5.3.1 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, 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 Agreement 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 Agreement is in effect. The Interconnection Customer may assign such repayment rights to any person.

If the Small 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.

5.3.2 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 SGIP. 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. 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.

5.3.3 Rights Under Other Agreements

Notwithstanding any other provision of this Agreement, 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 Small Generating Facility.

Article 6. Billing, Payment, Milestones, and Financial Security

6.1 Billing and Payment Procedures and Final Accounting

6.1.1 The Participating TO shall bill the Interconnection Customer for the design, engineering, construction, and procurement costs of Interconnection Facilities and Upgrades contemplated by this Agreement on a monthly basis, or as otherwise agreed by the Parties. The Interconnection Customer shall pay each bill within 30 calendar days of receipt, or as otherwise agreed to by the Parties. Notwithstanding the foregoing, any invoices between the ISO and another Party shall be submitted and paid in accordance with the ISO Tariff.

6.1.2 Within three months of completing the construction and installation of the Participating TO's Interconnection Facilities and/or Upgrades described in the Attachments to this Agreement, the Participating TO shall provide the Interconnection Customer with a final accounting report of any difference between (1) the Interconnection Customer's cost responsibility for the actual cost of such facilities or Upgrades, and (2) the Interconnection Customer's previous aggregate payments to the Participating TO for such facilities or Upgrades. If the Interconnection Customer's cost responsibility exceeds its previous aggregate payments, the Participating TO shall invoice the Interconnection Customer for the amount due and the Interconnection Customer shall make payment to the Participating TO within 30 calendar days. If the Interconnection Customer's previous aggregate payments exceed its cost responsibility under this Agreement, the Participating TO shall refund to the Interconnection Customer an amount equal to the difference within 30 calendar days of the final accounting report.

6.2 Milestones

The Parties shall agree on milestones for which each Party is responsible and list them in Attachment 4 of this Agreement. A Party's obligations under this provision may be extended by agreement. If a Party anticipates that it will be unable to meet a milestone for any reason other than a Force Majeure Event, as defined in article 7.5.1, it shall immediately notify the other Parties of the reason(s) for not meeting the milestone and (1) propose the earliest reasonable alternate date by which it can attain this and future milestones, and (2) request appropriate amendments to Attachment 4. The Parties affected by the failure to meet a milestone shall not unreasonably withhold agreement to such an amendment unless (1) they will suffer significant uncompensated economic or operational harm from the delay, (2) attainment of the same milestone has previously been delayed, or (3) they have reason to believe that the delay in meeting the milestone is intentional or unwarranted notwithstanding the circumstances explained by the Party proposing the amendment.

6.3 Financial Security Arrangements

At least 20 Business Days prior to the commencement of the design, procurement, installation, or construction of a discrete portion of the Participating TO's Interconnection Facilities and Upgrades, the Interconnection Customer shall provide the Transmission Provider, 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 where the Point of Interconnection is located. Such security for payment shall be in an amount sufficient to cover the costs for constructing, designing, procuring, and installing the applicable portion of the Participating TO's Interconnection Facilities and Upgrades and shall be reduced on a dollar-for-dollar basis for payments made to the Participating TO under this Agreement during its term. In addition:

6.3.1 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.

6.3.2 The letter of credit or surety bond must be issued by a financial institution or insurer reasonably acceptable to the Participating TO and must specify a reasonable expiration date.

Article 7. Assignment, Liability, Indemnity, Force Majeure, Consequential Damages, and Default

7.1 Assignment

This Agreement may be assigned by any Party upon 15 Business Days prior written notice and opportunity to object by the other Parties; provided that:

7.1.1 Any Party may assign this Agreement 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 Agreement, provided that the Interconnection Customer promptly notifies the Participating TO and the ISO of any such assignment;

7.1.2 The Interconnection Customer shall have the right to assign this Agreement, without the consent of the Participating TO or the ISO, for collateral security purposes to aid in providing financing for the Small Generating Facility, provided that the Interconnection Customer will promptly notify the Participating TO and the ISO of any such assignment.

7.1.3 Any attempted assignment that violates this article is void and ineffective. Assignment shall not relieve a Party of its obligations, nor shall a Party's obligations be enlarged, in whole or in part, by reason thereof. An assignee is responsible for meeting the same financial, credit, and insurance obligations as the Interconnection Customer. Where required, consent to assignment will not be unreasonably withheld, conditioned or delayed.

7.2 Limitation of Liability

Each Party's liability to the other Parties for any loss, cost, claim, injury, liability, or expense, including reasonable attorney's fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall any Party be liable to the other Parties for any indirect, special, consequential, or punitive damages, except as authorized by this Agreement.

7.3 Indemnity

7.3.1 This provision protects each Party from liability incurred to third parties as a result of carrying out the provisions of this Agreement. Liability under this provision is exempt from the general limitations on liability found in article 7.2.

7.3.2 The Parties shall at all times indemnify, defend, and hold the other Parties harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from another Party's action or failure to meet its obligations under this Agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7.3.3 If an indemnified Party is entitled to indemnification under this article as a result of a claim by a third party, and the indemnifying Party fails, after notice and reasonable opportunity to proceed under this article, 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.

7.3.4 If an indemnifying Party is obligated to indemnify and hold any indemnified Party harmless under this article, 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.

7.3.5 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 this article 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.

7.4 Consequential Damages

Other than as expressly provided for in this Agreement, no Party shall be liable under any provision of this Agreement 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.

7.5 Force Majeure

7.5.1 As used in this article, a Force Majeure Event 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 an act of negligence or intentional wrongdoing by the Party claiming Force Majeure."

7.5.2 If a Force Majeure Event prevents a Party from fulfilling any obligations under this Agreement, the Party affected by the Force Majeure Event (Affected Party) shall promptly notify the other Parties, either in writing or via the telephone, of the existence of the Force Majeure Event. The notification must specify in reasonable detail the circumstances of the Force Majeure Event, its expected duration, and the steps that the Affected Party is taking to mitigate the effects of the event on its performance. The Affected Party shall keep the other Parties informed on a continuing basis of developments relating to the Force Majeure Event until the event ends. The Affected Party will be entitled to suspend or modify its performance of obligations under this Agreement (other than the obligation to make payments) only to the extent that the effect of the Force Majeure Event cannot be mitigated by the use of Reasonable Efforts. The Affected Party will use Reasonable Efforts to resume its performance as soon as possible.

7.6 Default

7.6.1 No Default shall exist where such failure to discharge an obligation (other than the payment of money) is the result of a Force Majeure Event as defined in this Agreement or the result of an act or omission of another Party. Upon a Default, the affected non-defaulting Party(ies) shall give written notice of such Default to the defaulting Party. Except as provided in article 7.6.2, the defaulting Party shall have 60 calendar days from receipt of the Default notice within which to cure such Default; provided however, if such Default is not capable of cure within 60 calendar days, the defaulting Party shall commence such cure within 20 calendar days after notice and continuously and diligently complete such cure within six months from receipt of the Default notice; and, if cured within such time, the Default specified in such notice shall cease to exist.

- 7.6.2 If a Default is not cured as provided in this article, or if a Default is not capable of being cured within the period provided for herein, the affected non-defaulting Party(ies) shall have the right to terminate this Agreement 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 Agreement, to recover from the defaulting 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 Agreement.

Article 8. Insurance

- 8.1 The Interconnection Customer shall, at its own expense, maintain in force general liability insurance without any exclusion for liabilities related to the interconnection undertaken pursuant to this Agreement. The amount of such insurance shall be sufficient to insure against all reasonably foreseeable direct liabilities given the size and nature of the generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made. The Interconnection Customer shall obtain additional insurance only if necessary as a function of owning and operating a generating facility. Such insurance shall be obtained from an insurance provider authorized to do business in the State where the interconnection is located. Certification that such insurance is in effect shall be provided upon request of the Participating TO or ISO, except that the Interconnection Customer shall show proof of insurance to the Participating TO and ISO no later than ten Business Days prior to the anticipated Commercial Operation Date. If the Interconnection Customer is of sufficient credit-worthiness, it may propose to self-insure for such liabilities, and such a proposal shall not be unreasonably rejected.
- 8.2 The Participating TO agrees to maintain general liability insurance or self-insurance consistent with the Participating TO's commercial practice. Such insurance or self-insurance shall not exclude coverage for the Participating TO's liabilities undertaken pursuant to this Agreement.
- 8.3 The ISO agrees to maintain general liability insurance or self-insurance consistent with the ISO's commercial practice. Such insurance shall not exclude coverage for the ISO's liabilities undertaken pursuant to this Agreement.
- 8.4 The Parties further agree to notify each other whenever an accident or incident occurs resulting in any injuries or damages that are included within the scope of coverage of such insurance, whether or not such coverage is sought.

Article 9. Confidentiality

- 9.1 Confidential Information shall mean any confidential and/or proprietary information provided by one Party to another Party that is clearly marked or otherwise designated "Confidential." For purposes of this Agreement all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed Confidential Information regardless of whether it is clearly marked or otherwise designated as such.
- 9.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Parties and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce this Agreement. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor to the public without the prior written authorization from the Party providing that information, except to fulfill obligations under this Agreement, or to fulfill legal or regulatory requirements.

- 9.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Parties as it employs to protect its own Confidential Information.
- 9.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.
- 9.3 Notwithstanding anything in this article to the contrary, and pursuant to 18 CFR § 1b.20, if FERC, 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 Agreement, the Party shall provide the requested information to FERC, within the time provided for in the request for information. In providing the information to FERC, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by FERC and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Parties to this Agreement prior to the release of the Confidential Information to FERC. The Party shall notify the other Parties to this Agreement when it is notified by FERC 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 CFR § 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.

Article 10. Disputes

All disputes arising out of or in connection with this Agreement whereby relief is sought by or from 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 reference to this Agreement. Disputes arising out of or in connection with this Agreement not subject to provisions of Article 13 of the ISO Tariff shall be resolved as follows:

- 10.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.
- 10.2 In the event of a dispute, either Party shall provide the other Party with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.
- 10.3 If the dispute has not been resolved within two Business Days after receipt of the Notice, either Party may contact FERC's Dispute Resolution Service (DRS) for assistance in resolving the dispute.
- 10.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. DRS can be reached at 1-877-337-2237 or via the internet at <http://www.ferc.gov/legal/adr.asp>.
- 10.5 Each Party agrees to conduct all negotiations in good faith and will be responsible for one-half of any costs paid to neutral third-parties.
- 10.6 If neither Party elects to seek assistance from the DRS, or if the attempted dispute resolution fails, then either Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of this Agreement.

Article 11. Taxes

- 11.1 The Parties agree to follow all applicable tax laws and regulations, consistent with FERC policy and Internal Revenue Service requirements.
- 11.2 Each Party shall cooperate with the other Parties to maintain the other Parties' tax status. Nothing in this Agreement is intended to adversely affect the Participating TO's tax exempt status with respect to the issuance of bonds including, but not limited to, local furnishing bonds.

Article 12. Miscellaneous

- 12.1 Governing Law, Regulatory Authority, and Rules
The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of _____ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.
- 12.2 Amendment
The Parties may amend this Agreement by a written instrument duly executed by all of the Parties, or under article 12.12 of this Agreement.
- 12.3 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.
- 12.4 Waiver
- 12.4.1 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.
- 12.4.2 Any waiver at any time by any 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. Termination or Default of this Agreement for any reason by 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 Agreement shall, if requested, be provided in writing.
- 12.5 Entire Agreement
This Agreement, including all Attachments, 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 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 Agreement.
- 12.6 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.

12.7 No Partnership

This Agreement 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.

12.8 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

12.9 Security Arrangements

Infrastructure security of **electric system** equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. FERC expects **all transmission providers**, market participants, and interconnection customers interconnected to **electric systems** 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 are expected to meet basic standards for system infrastructure and operational security, including physical, operational, and cyber-security practices.

12.10 Environmental Releases

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 Small Generating Facility or the Interconnection Facilities, each of which may reasonably be expected to affect the other Parties. The notifying Party shall (1) provide the notice as soon as practicable, provided such Party makes a good faith effort to provide the notice no later than 24 hours after such Party becomes aware of the occurrence, and (2) promptly furnish to the other Parties copies of any publicly available reports filed with any governmental authorities addressing such events.

12.11 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Parties for the performance of such subcontractor.

12.11.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Parties 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 Participating TO or the ISO be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

12.11.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

12.12 Reservation of Rights

The ISO and Participating TO shall each have the right to make a unilateral filing with FERC to modify this 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 the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; 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 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, except to the extent that the Parties otherwise mutually agree as provided herein.

Article 13. Notices

13.1 General

Unless otherwise provided in this Agreement, any written notice, demand, or request required or authorized in connection with this Agreement ("Notice") shall be deemed properly given if delivered in person, delivered by recognized national courier service, or sent by first class mail, postage prepaid, to the person specified below:

If to the Interconnection Customer:

Interconnection Customer: _____
Attention: _____
Address: _____
City: _____ State: _____ Zip: _____
Phone: _____ Fax: _____

If to the Participating TO:

Participating TO: _____
Attention: _____
Address: _____
City: _____ State: _____ Zip: _____
Phone: _____ Fax: _____

If to the ISO:

California Independent System Operator
Attention: _____
151 Blue Ravine Road
Folsom, CA 95630
Phone: 916-351-4400 Fax: _____

13.2 Billing and Payment

Billings and payments shall be sent to the addresses set out below:

Interconnection Customer: _____
Attention: _____
Address: _____
City: _____ State: _____ Zip: _____

Participating TO: _____
Attention: _____
Address: _____
City: _____ State: _____ Zip: _____

13.3 Alternative Forms of Notice

Any notice or request required or permitted to be given by any Party to the other Parties and not required by this Agreement 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 below:

If to the Interconnection Customer:

Interconnection Customer: _____
Attention: _____
Address: _____
City: _____ State: _____ Zip: _____
Phone: _____ Fax: _____

If to the Participating TO:

Participating TO: _____
Attention: _____
Address: _____
City: _____ State: _____ Zip: _____
Phone: _____ Fax: _____

If to the ISO:

California Independent System Operator
Attention: _____
151 Blue Ravine Road
Folsom, CA 95630
Phone: 916-351-4400 Fax: _____

13.4 Designated Operating Representative

The Parties may also designate operating representatives to conduct the communications which may be necessary or convenient for the administration of this Agreement. This person will also serve as the point of contact with respect to operations and maintenance of the Party's facilities.

Interconnection Customer's Operating Representative:

Interconnection Customer: _____
Attention: _____
Address: _____
City: _____ State: _____ Zip: _____
Phone: _____ Fax: _____

Participating TO's Operating Representative:

Participating TO: _____
Attention: _____
Address: _____
City: _____ State: _____ Zip: _____
Phone: _____ Fax: _____

ISO's Operating Representative

California Independent System Operator
Attention: _____
151 Blue Ravine Road
Folsom, CA 95630
Phone: 916-351-4400 Fax: _____

13.5 Changes to the Notice Information

Any Party may change this information by giving five Business Days written notice to the other Parties prior to the effective date of the change.

Article 14. Signatures

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

For the California Independent System Operator

Name: _____

Title: _____

Date: _____

For the Participating TO

Name: _____

Title: _____

Date: _____

For the Interconnection Customer

Name: _____

Title: _____

Date: _____

Attachment 1

Glossary of Terms

Affected System – 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.

Applicable Laws and Regulations – 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.

Business Day – Monday through Friday, excluding federal holidays and the day after Thanksgiving Day.

Commercial Operation Date – The date on which a Small Generating Facility commenced generating electricity for sale as agreed upon by the Participating TO and the Interconnection Customer.

Control Area – 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 – The failure of a breaching Party to cure its breach under this Agreement.

Distribution System – Those non-ISO-controlled transmission and distribution facilities owned by the Participating TO.

Distribution Upgrades – The additions, modifications, and upgrades to the Participating TO's Distribution System. Distribution Upgrades do not include Interconnection Facilities.

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.

Governmental Authority – 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.

Interconnection Facilities – The Participating TO's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the Participating TO's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades or Network Upgrades.

Interconnection Handbook – A handbook, developed by the Participating TO and posted on the Participating TO's web site or otherwise made available by the Participating TO, describing technical and operational requirements for wholesale generators and loads connected to the Participating TO's

Transmission System, as such handbook may be modified or superseded from time to time. The Participating TO's standards contained in the Interconnection Handbook shall be deemed consistent with Good Utility Practice and applicable reliability standards.

Interconnection Request – A request, in accordance with the ISO Tariff, to interconnect a new Small Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Small Generating Facility that is interconnected with the ISO Controlled Grid.

ISO Controlled Grid – 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 – The ISO's tariff, as filed with FERC, and as amended or supplemented from time to time, or any successor tariff.

Material Modification – A modification that has a material impact on the cost or timing of any Interconnection Request or any other valid interconnection request with a later queue priority date.

Network Upgrades – Additions, modifications, and upgrades to the Participating TO's Transmission System required at or beyond the point at which the Small Generating Facility interconnects with the ISO Controlled Grid to accommodate the interconnection of the Small Generating Facility with the ISO Controlled Grid. Network Upgrades do not include Distribution Upgrades.

Operational Control – 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.

Operating Requirements – Any operating and technical requirements that may be applicable due to the ISO, Western Electricity Coordinating Council, Control Area, or the Participating TO's requirements, including those set forth in this Agreement.

Party or Parties – The Participating TO, ISO, Interconnection Customer or the applicable combination of the above.

Point of Interconnection – The point where the Interconnection Facilities connect with the Participating TO's Transmission System.

Reasonable Efforts – With respect to an action required to be attempted or taken by a Party under this Agreement, 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.

Small Generating Facility – The Interconnection Customer's device for the production of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Transmission Control Agreement – ISO FERC Electric Tariff No. 7.

Transmission System – 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.

Upgrades – The required additions and modifications to the Participating TO's Transmission System and Distribution System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

Attachment 2

**Description and Costs of the Small Generating Facility,
Interconnection Facilities, and Metering Equipment**

Equipment, including the Small Generating Facility, Interconnection Facilities, and metering equipment shall be itemized and identified as being owned by the Interconnection Customer or the Participating TO. The Participating TO will provide a best estimate itemized cost, including overheads, of its Interconnection Facilities and metering equipment, and a best estimate itemized cost of the annual operation and maintenance expenses associated with its Interconnection Facilities and metering equipment.

Attachment 3

**One-line Diagram Depicting the Small Generating Facility, Interconnection
Facilities, Metering Equipment, and Upgrades**

Attachment 4

Milestones

In-Service Date: _____

Critical milestones and responsibility as agreed to by the Parties:

	Milestone/Date	Responsible Party
(1)	_____	_____
(2)	_____	_____
(3)	_____	_____
(4)	_____	_____
(5)	_____	_____
(6)	_____	_____
(7)	_____	_____
(8)	_____	_____
(9)	_____	_____
(10)	_____	_____

Agreed to by:

For the ISO _____ Date _____

For the Participating TO _____ Date _____

For the Interconnection Customer _____ Date _____

Attachment 5

Additional Operating Requirements for the ISO Controlled Grid and Affected Systems Needed to Support the Interconnection Customer's Needs

The Participating TO and the ISO shall also provide requirements that must be met by the Interconnection Customer prior to initiating parallel operation with the ISO Controlled Grid.

Attachment 6

**Participating TO's Description of its Upgrades
and Best Estimate of Upgrade Costs**

The Participating TO shall describe Upgrades and provide an itemized best estimate of the cost, including overheads, of the Upgrades and annual operation and maintenance expenses associated with such Upgrades. The Participating TO shall functionalize Upgrade costs and annual expenses as either transmission or distribution related.

Attachment 7

INTERCONNECTION REQUIREMENTS FOR A WIND GENERATING PLANT

Attachment 7 sets forth requirements and provisions specific to a wind generating plant. All other requirements of this Agreement 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 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.

6. 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.
7. 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.
8. Wind generating plants may be tripped after the fault period if this action is intended as part of a special protection system.
9. 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.
10. Existing individual generator units that are, or have been, interconnected to the network at the same location at the effective date of the Attachment 7 LVRT Standard are exempt from meeting the Attachment 7 LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Attachment 7 LVRT Standard.

Post-transition Period LVRT Standard

All wind generating plants 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 Attachment 7 LVRT Standard are exempt from meeting the Attachment 7 LVRT Standard for the remaining life of the existing generation equipment. Existing individual generator units that are replaced are required to meet the Attachment 7 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 Agreement in order to maintain a specified voltage schedule, if the 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 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.

Attachment 8

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: _____

ISO TARIFF APPENDIX EE

Transmission Expansion and Planning Process

PART A. Transmission Expansion and Planning Process

24.1 Determination of Need for Proposed Transmission Projects.

A Participating TO, Market Participant, the CAISO, the CPUC, or CEC may propose a transmission system addition or upgrade, and the CAISO will determine, in accordance with this Section 24.1 of this Appendix EE, whether the transmission addition or upgrade is needed, where it will (1) promote economic efficiency, (2) maintain System Reliability, (3) satisfy the requirements of a Location Constrained Resource Interconnection Facility, or (4) maintain the simultaneous feasibility of allocated Long-Term CRRs. CAISO management can determine the need for transmission additions or upgrades with an estimated capital investment of less than \$50 million without CAISO Governing Board approval. The determination of need by CAISO management for transmission additions or upgrades with an estimated capital cost of \$50 million or more must be approved by the CAISO Governing Board.

24.1.1 Economically Driven Projects.

The determination that a transmission addition or upgrade is needed to promote economic efficiency shall be made in accordance with this Section 24 of this Appendix EE and the Business Practice Manual in any of the following ways:

- (a) Where a Project Sponsor proposes a Merchant Transmission Facility and demonstrates to the CAISO the financial capability to pay the full cost of construction and operation of the Merchant Transmission Facility. The Merchant Transmission Facility must mitigate all operational concerns identified under Section 24.5 of this Appendix EE to the satisfaction of the CAISO, in consultation with the Participating TO(s) in whose PTO Service Territory the Merchant Transmission Facility will be located, and ensure the continuing feasibility of

allocated Long Term CRRs over the length of their terms. To ensure that the Project Sponsor is financially able to pay the construction and operating costs of the Merchant Transmission Facility, and where the Participating TO is not the Project Sponsor and is to construct the Merchant Transmission Facility under Section 24.1 of this Appendix EE, the CAISO in cooperation with the Participating TO may require (1) a demonstration of creditworthiness (e.g., an appropriate credit rating), or (2) sufficient security in the form of an unconditional and irrevocable letter of credit or other similar security sufficient to meet its responsibilities and obligations for the full costs of the transmission addition or upgrade.

- (b) Where a Project Sponsor, the CPUC, or CEC proposes a transmission addition or upgrade during the Request Window and the project is approved by the CAISO Governing Board, or a Participating TO proposes a transmission upgrade or addition to an existing transmission facility with an estimated capital cost of less than \$50 million in accordance with the Study Plan and the project is included in the CAISO annual Transmission Plan. In determining whether to approve the project, the CAISO Governing Board or CAISO management, as applicable, shall consider the degree to which, if any, the benefits of the project outweigh the costs, in accordance with the procedures and using the technical studies set forth in the Business Practice Manual. The benefits of the project may include, but need not be limited to, a calculation of any reduction in production costs, Congestion costs, Transmission Losses, capacity or other

electric supply costs resulting from improved access to cost-efficient resources, and environmental costs. The cost of the project must consider any estimated costs identified under Section 24.1.4 of this Appendix EE to maintain the simultaneous feasibility of allocated Long Term CRRs for the length of their term. The CAISO management or CAISO Governing Board, as appropriate, in determining whether to approve or recommend the project, shall also consider the comparative costs and benefits of viable alternatives to the proposed transmission upgrade or addition, including (1) other transmission additions or upgrades, or the effects of other transmission additions or upgrades proposed under Section 24.2 of this Appendix EE during the Transmission Planning Process cycle, (2) Demand-side management, (3) acceleration or expansion of any transmission upgrade or addition already approved by the CAISO Governing Board or included in any CAISO annual Transmission Plan, or (4) Generation.

- (c) Where the CAISO proposes a transmission addition or upgrade during the CAISO's Transmission Planning Process and the project is approved by the CAISO Governing Board or included in the CAISO annual Transmission Plan, as appropriate. In determining whether to approve the CAISO proposed transmission addition or upgrade, the CAISO Governing Board and CAISO management shall apply the same factors set forth in Section 24.1.1(b) of this Appendix EE. If approved by the CAISO Governing Board or CAISO management, as appropriate, the CAISO will designate one or more of the Participating TOs with PTO Service Territories in which the terminus of the transmission addition or upgrade will be located to act as Project Sponsor.

Where two or more Participating TOs are designated as Project Sponsors, such CAISO designation will include the proportionate responsibility between or among Participating TOs to own, construct, and finance the transmission addition or upgrade. If a Participating TO refuses to act as a Project Sponsor under this Section 24.1.1(c) of this Appendix EE, the CAISO will first request other designated Participating TO(s) to assume the remainder or greater proportionate responsibility, and if no other Participating TO had been designated or is willing to increase its proportionate responsibility, the CAISO may solicit bids to finance, own, and construct the transmission addition or upgrade.

24.1.1.1 Information Requirements for Economic Transmission Projects.

The Project Sponsor and relevant Participating TOs shall provide any necessary assistance and information to the CAISO to enable the CAISO to determine that a transmission upgrade or addition is needed to promote economic efficiency, and will perform all studies required by the adopted Study Plan in a manner consistent with the Business Practice Manual. A Project Sponsor of an economically driven transmission upgrade or addition to promote economic efficiency under Section 24.1.1 of this Appendix EE shall also provide in its proposal a statement whether the proposed upgrade or addition will be a Merchant Transmission Facility.

24.1.2 Reliability Driven Projects.

The CAISO in coordination with each Participating TO with a PTO Service Territory will, consistent with the procedures set forth in the Business Practice Manual, identify the need for any transmission additions or upgrades required to ensure System Reliability consistent with all Applicable Reliability Criteria and CAISO Planning Standards. In making this determination, the CAISO, in coordination with each Participating TO with a PTO Service Territory and other Market Participants, shall consider lower cost

alternatives to the construction of transmission additions or upgrades, such as acceleration or expansion of existing projects, Demand-side management, Remedial Action Schemes, appropriate Generation, interruptible Loads or reactive support. The CAISO shall direct each Participating TO with a PTO Service Area, as a registered Transmission Planner with NERC, to perform the necessary studies, based on the Unified Planning Assumptions and Study Plan as set forth in Section 24.2.3 of this Appendix EE and in accordance with the Business Practice Manual, to determine the facilities needed to meet all Applicable Reliability Criteria and CAISO Planning Standards. The Participating TO with a PTO Service Area shall provide the CAISO and other Market Participants with all information relating to the studies performed under this Section, subject to any limitation provided in Section 20.2 of the CAISO Tariff. The CAISO shall be free to propose any transmission upgrades or additions it deems necessary to ensure System Reliability consistent with Applicable Reliability Criteria and CAISO Planning Standards. The Participating TO with a PTO Service Territory in which the transmission upgrade or addition deemed needed under this Section 24.1.2 of this Appendix EE is to be located shall be the Project Sponsor, with the responsibility to construct, own and finance, and maintain such transmission upgrade or addition.

24.1.3. Location Constrained Resource Interconnection Facility Projects.

The CAISO, CPUC, CEC, a Participating TO or any other Market Participant may propose a transmission addition as a Location Constrained Resource Interconnection Facility. A proposal shall include the following information, to the extent available:

- (a) Information showing that the proposal meets the requirements of Section 24.1.3.1 of this Appendix EE; and
- (b) A description of the proposed facility, including the following information:
 - (1) Transmission studies demonstrating that the proposed facility satisfies Applicable Reliability Criteria and CAISO Planning Standards;

- (2) Identification of the most feasible and cost-effective alternative transmission additions, which may include network upgrades, that would accomplish the objective of the proposal;
- (3) A planning level cost estimate for the proposed facility and all proposed alternatives;
- (4) An assessment of the potential for the future connection of further transmission additions that would convert the proposed facility into a network transmission facility, including conceptual plans;
- (5) The estimated in-service date of the proposed facility; and
- (6) A conceptual plan for connecting potential LCRIGs, if known, to the proposed facility.

24.1.3.1 Criteria for Qualification as a Location Constrained Resource Interconnection Facility.

- (a) The CAISO shall conditionally approve a facility as a Location Constrained Resource Interconnection Facility if it determines that the facility is needed and all of the following requirements are met:
 - (1) The facility is to be constructed for the primary purpose of connecting to the CAISO Controlled Grid two or more Location Constrained Resource Interconnection Generators in an Energy Resource Area, and at least one of the Location Constrained Resource Interconnection Generators is to be owned by an entity(ies) that is not an Affiliate of the owner(s) of another Location Constrained Resource Interconnection Generator in that Energy Resource Area;
 - (2) The facility will be a High Voltage Transmission Facility;

- (3) At the time of its in-service date, the facility will not be a network facility and would not be eligible for inclusion in a Participating TO's TRR other than as an LCRIF; and
 - (4) The facility meets Applicable Reliability Criteria and CAISO Planning Standards.
- (b) The proponent of a facility that has been determined by the CAISO to meet the requirements of Section 24.1.3.1(a) of this Appendix EE shall provide the CAISO with information concerning the requirements of this subsection not less than ninety (90) days prior to the planned commencement of construction, and the facility shall qualify as a Location Constrained Resource Interconnection Facility if the CAISO determines that both of the following requirements are met:
- (1) The addition of the capital cost of the facility to the High Voltage TRR of a Participating TO will not cause the aggregate of the net investment of all LCRIFs (net of the amount of the capital costs of LCRIFs to be recovered from LCRIGs pursuant to Section 26.6) included in the High Voltage TRRs of all Participating TOs to exceed fifteen percent (15%) of the aggregate of the net investment of all Participating TOs in all High Voltage Transmission Facilities reflected in their High Voltage TRRs (net of the amount of the capital costs of LCRIFs to be recovered from LCRIGs pursuant to Section 26.6) in effect at the time of the CAISO's evaluation of the facility); and
 - (2) Existing or prospective owners of LCRIGs have demonstrated their interest in connecting LCRIGs to the facility consistent with the requirements of Section 24.1.3.2 of this Appendix EE, which establishes the necessary demonstration of interest.

- (c) Each Participating TO shall report annually to the CAISO the amount of its net investment in LCRIFs (net of the amount of the capital costs of LCRIFs to be recovered from LCRIGs pursuant to Section 26.6), the portion of the capital costs of LCRIFs credited to its TRR, and its net investment in High Voltage Transmission Facilities reflected in its High Voltage TRR (net of the amount of the capital costs of LCRIFs to be recovered from LCRIGs pursuant to Section 26.6), to enable the CAISO to make the determination required under Section 24.1.3.1(b)(1) of this Appendix EE.

24.1.3.2 Demonstration of Interest in a Location Constrained Resource Interconnection Facility.

A proponent of an LCRIF must demonstrate interest in the LCRIF equal to sixty percent (60%) or more of the capacity of the facility in the following manner:

- (a) the proponent's demonstration must include a showing that LCRIGs that would connect to the facility and would have a combined capacity equal to at least twenty-five percent (25%) of the capacity of the facility have executed Large Generator Interconnection Agreements or Small Generator Interconnection Agreements, as applicable; and
- (b) to the extent the showing pursuant to Section 24.1.3.2(a) of Appendix EE does not constitute sixty percent (60%) of the capacity of the LCRIF, the proponent's demonstration of the remainder of the required minimum level of interest must include a showing that additional LCRIGs:
- (1) have obtained control over their site or paid a deposit to the CAISO in the amount of \$250,000, which deposit shall be refundable if the LCRIF is not approved or is withdrawn by the proponent; and
 - (2) have demonstrated interest in the LCRIF by one of the following methods:
 - (i) executing a firm power sales agreement for the output of the LCRIG for a period of five years or longer; or

- (ii) being in the CAISO's interconnection queue and paying a deposit to the CAISO equal to the sum of the minimum deposits required of an Interconnection Customer for all studies performed in accordance with the Large Generator Interconnection Procedures or Small Generator Interconnection Procedures, as applicable to the LCRIG, less the amount of any deposits actually paid by the LCRIG for such studies. The deposit shall be credited toward such study costs. If the LCRIF is not approved or is withdrawn by the proponent, any deposit paid under this provision shall be refundable to the extent it exceeds costs incurred by the CAISO for such studies; or
- (iii) paying a deposit to the CAISO equal to five percent (5%) of the LCRIG's pro rata share of the capital costs of a proposed LCRIF. The deposit shall be credited toward study costs performed in connection with the Large Generator Interconnection Procedures or Small Generator Interconnection Procedures, whichever is applicable. If the LCRIF is not approved or is withdrawn by the proponent, any deposit paid under this provision shall be refundable to the extent it exceeds the costs incurred by the CAISO for such studies.

24.1.3.3 Coordination With Transmission Additions Proposed by Non-Participating TOs.

In the event that a facility proposed as an LCRIF would connect to LCRIGs in an Energy Resource Area that would also be connected by a transmission facility that is in existence or is proposed to be constructed by an entity that is not a Participating TO and that does not intend to place that facility under the Operational Control of the CAISO, the CAISO shall coordinate with the entity owning or proposing that transmission facility through any regional planning process to avoid the unnecessary construction of duplicative transmission additions to connect the same LCRIGs to the CAISO Controlled Grid.

24.1.3.4 Evaluation of Location Constrained Resource Interconnection Facilities.

In evaluating whether a proposed LCRIF that meets the requirements of Section 24.1.3.1 of this Appendix EE is needed, and for purposes of ranking and prioritizing LCRIF projects, the CAISO will consider the following factors:

- (a) Whether, and if so, the extent to which, the facility meets or exceeds applicable CAISO Planning Standards, including standards that are Applicable Reliability Criteria.
- (b) Whether, and if so, the extent to which, the facility has the capability and flexibility both to interconnect potential LCRIGs in the Energy Resource Area and to be converted in the future to a network transmission facility.
- (c) Whether the projected cost of the facility is reasonable in light of its projected benefits, in comparison to the costs and benefits of other alternatives for connecting Generating Units or otherwise meeting a need identified in the CAISO Transmission Planning Process, including alternatives that are not LCRIFs. In making this determination, the CAISO shall take into account, among other factors, the following:
 - (1) The potential capacity of LCRIGs and the potential Energy that could be produced by LCRIGs in each Energy Resource Area;
 - (2) The capacity of LCRIGs in the CAISO's interconnection queue for each Energy Resource Area;
 - (3) The projected cost and in-service date of the facility in comparison with other transmission facilities that could connect LCRIGs to the CAISO Controlled Grid;
 - (4) Whether, and if so, the extent to which, the facility would provide additional reliability or economic benefits to the CAISO Controlled Grid; and
 - (5) Whether, and if so, the extent to which, the facility would create a risk of stranded costs.

24.1.4 Maintaining the Feasibility of Allocated Long Term CRRs.

The CAISO is obligated to ensure the continuing feasibility of Long Term CRRs that are allocated by the CAISO over the length of their terms. In furtherance of this requirement the CAISO shall, as part of its annual Transmission Planning Process cycle, test and evaluate the simultaneous feasibility of allocated Long Term CRRs, including, but not limited to, when acting on the following types of projects: (a) planned or proposed transmission projects; (b) Generating Unit or transmission retirements; (c) Generating Unit interconnections; and (d) the interconnection of new Load. Pursuant to such evaluations the CAISO shall identify the need for any transmission additions or upgrades required to ensure the continuing feasibility of allocated Long Term CRRs over the length of their terms. In assessing the need for transmission additions or upgrades to maintain the feasibility of allocated Long Term CRRs, the CAISO, in coordination with the Participating TOs and other Market Participants, shall consider lower cost alternatives to the construction of transmission additions or upgrades, such as acceleration or expansion of existing projects; Demand-side management; Remedial Action Schemes; constrained-on Generation; interruptible Loads; reactive support; or in cases where the infeasible Long Term CRRs involve a small magnitude of megawatts, ensuring against the risk of any potential revenue shortfall using the CRR Balancing Account and uplift mechanism in Section 11.2.4 of the CAISO Tariff. As part of the CAISO's Transmission Planning Process, the Participating TOs and Market Participants shall provide the necessary assistance and information to the CAISO to allow it to assess and identify transmission additions or upgrades that may be necessary under Section 24.1.4 of this Appendix EE. To the extent a transmission upgrade or addition is deemed needed to maintain the feasibility of allocated Long Term CRRs in accordance with this Section and included in the CAISO's annual Transmission Plan, the CAISO will designate the Participating TO(s) with a PTO Service Territory in which the transmission upgrade or addition is to be located as the Project Sponsor(s), responsible to construct, own and/or finance, and maintain such transmission upgrade or addition.

24.2 Transmission Planning and Coordination.

The CAISO shall perform the CAISO's Transmission Planning Process on an annual cycle in accordance with the terms of this CAISO Tariff, the Transmission Control Agreement, and the Business Practice Manual. The Transmission Planning Process shall, at a minimum:

- (a) Coordinate and consolidate the transmission needs of the CAISO Control Area into a single plan, which will be assessed on the basis of maintaining the reliability of the CAISO Controlled Grid in accordance with Applicable Reliability Criteria and CAISO Planning Standards, in a manner that promotes the economic efficiency of the CAISO Controlled Grid and considers federal and state environmental and other policies affecting the provision of Energy.
- (b) Reflect a planning horizon covering a minimum of ten (10) years that considers transmission enhancements and expansions, Demand Forecasts, Demand-side management, and capacity forecasts relating to generation technology type, additions and retirements, and such other factors as the CAISO determines are relevant.
- (c) Seek to avoid unnecessary duplication of facilities and ensure the simultaneous feasibility of the CAISO Transmission Plan and the transmission plans of interconnected Control Areas, and otherwise coordinate with regional and sub-regional transmission planning processes and entities in accordance with Section 24.8 of this Appendix EE.
- (d) Identify existing and projected limitations of the CAISO Controlled Grid's physical, economic or operational capability or performance and identify transmission upgrades and additions, including alternatives thereto, deemed needed in accordance with Section 24.1 of this Appendix EE to address the existing and projected limitations.

- (e) Account for any effects on the CAISO Controlled Grid of the interconnection of Generating Units on the Distribution System under the Wholesale Distribution Access Tariffs of the Participating TOs, including an assessment of the deliverability of such Generating Units on a basis comparable to the Deliverability Assessment performed under Appendix U.

24.2.1 CAISO Planning Standards Committee.

The CAISO shall maintain a Planning Standards Committee, which shall be open to participation by all Market Participants, electric utility regulatory agencies within California, and other interested parties, to review, provide advice on, and propose modifications to CAISO Planning Standards for consideration by CAISO management and the CAISO Governing Board. The Planning Standards Committee shall meet, at a minimum, on an annual basis prior to publication of the draft Unified Planning Assumptions and Study Plan under Section 24.2.3 of this Appendix EE; however, additional meetings, web conferences, teleconferences may be scheduled as needed. Meetings of the Planning Standards Committee shall be noticed by Market Notice and such notice shall be posted to the CAISO Website. Teleconference capability will be made available for all meetings of the Planning Standards Committee. The CAISO Vice President of Planning and Infrastructure Development or his or her designee shall serve as chair of the Planning Standards Committee. All materials addressed at or relating to such meetings, including agendas, presentations, background papers, party comments, and minutes shall be posted to the CAISO Website. The chair of the Planning Standards Committee shall seek approval by the CAISO Governing Board of any modifications to the CAISO Planning Standards, as those CAISO Planning Standards exist as of the effective date of Section 24.2 of this Appendix EE, and must include in the report to the CAISO Governing Board a summary of the positions of parties with respect to the proposed modifications to the CAISO Planning Standards and the ground(s) for rejecting modifications, if any, proposed by Market Participants or other interested parties.

24.2.2 Request Window.

Market Participants may propose Economic Planning Studies and transmission upgrades or additions for inclusion in the annual Transmission Plan during a Request Window. The duration of the Request Window will be set forth in the Business Practice Manual and will occur in the year prior to the year in which the Transmission Plan is prepared. Proposals for Economic Planning Studies and transmission upgrades or additions must use the forms and satisfy the information and technical requirements set forth in the Business Practice Manual. Proposals for transmission additions or upgrades must be within or connect to the CAISO Control Area or CAISO Controlled Grid and proposals for Economic Planning Studies must be intended to promote competition or economic efficiency of serving Load within the CAISO Control Area, but may relate to Congestion relief or transmission capacity expansion outside the CAISO Control Area. The following proposals will only be considered in the Transmission Plan if proposed during the Request Window:

- (a) Economic transmission upgrades or additions proposed under Section 24.1.1 of this Appendix EE, except for projects costing less than \$50 million that are identified through Participating TO proposals provided pursuant to the Study Plan;
- (b) Location Constrained Resource Interconnection Facilities under Section 24.1.3 of this Appendix EE not identified by the CAISO as part of Interconnection Studies performed under the LGIP set forth in Appendix U;
- (c) Demand response programs that are proposed for inclusion in the base case or assumptions for the Transmission Plan or as alternatives to transmission additions or upgrades;
- (d) Generation projects that are proposed as solutions to Congestion identified in previously published Economic Planning Studies, for inclusion in long-term planning studies, or as alternatives to transmission additions or upgrades; and
- (e) Requests for Economic Planning Studies.

24.2.2.1 CAISO Assessment of Request Window Proposals.

Following the submittal of a proposal for a transmission addition or upgrade, Demand response program, or generation project during the Request Window in accordance with Section 24.2.2 of this Appendix EE, the CAISO will determine whether the proposal will be included in the Unified Planning Assumptions or Study Plan as appropriate. A proposal can only be included in the Unified Planning Assumptions or Study Plan upon the determination by the CAISO that:

- (a) the proposal satisfies the information requirements for the particular type of project submitted as set forth in templates included in the Business Practice Manual;
- (b) the proposal is not functionally duplicative of transmission upgrades or additions that have previously been approved by the CAISO; and
- (c) the proposal, if a sub-regional or regional project that affects other interconnected Control Areas, has been reviewed by the appropriate sub-regional or regional planning entity, is not inconsistent with such sub-regional or regional planning entity's preferred solution or project, and has been determined to be appropriate for inclusion in the CAISO Study Plan, rather than, or in addition to, being included in or deferred to the planning process of the sub-regional or regional planning entity.

In accordance with the schedule and procedures set forth in the Business Practice Manual, the CAISO will notify the Market Participant submitting the proposal of any deficiencies in the proposal and provide the Market Participant an opportunity to correct the deficiencies. The failure to correct the deficiency precludes the proposal from inclusion in the Study Plan. The CAISO will notify the Market Participant submitting the proposal whether or not the proposal will be included in the Study Plan.

24.2.2.2 CAISO Assessment of Requests for Economic Planning Studies Received During the Request Window.

Following the submittal of a request for an Economic Planning Study during the Request Window in accordance with Section 24.2.2 of this Appendix EE, the CAISO will determine whether the request shall be designated as a High Priority Economic Planning Study for inclusion in the Unified Planning Assumptions and Study Plan. In making the determination, the CAISO will consider:

- (a) Whether the requested Economic Planning Study seeks to address Congestion identified by the CAISO in the Congestion Data Summary published for the applicable Transmission Planning Process cycle and the magnitude, duration, and frequency of that Congestion;
- (b) Whether the requested Economic Planning Study addresses delivery of Generation from Location Constrained Resource Interconnection Generators or network transmission facilities intended to access Generation from an Energy Resource Area (ERA) or similar resource area assigned a high priority by the CPUC or CEC;
- (c) Whether the requested Economic Planning Study is intended to address Local Capacity Area Resource requirements; or
- (d) Whether resource and Demand information indicates that Congestion described in the Economic Planning Study request is projected to increase over the planning horizon used in the Transmission Planning Process and the magnitude of that Congestion.

In accordance with the schedule and procedures set forth in the Business Practice Manual, the CAISO will post to the CAISO Website the list of selected High Priority Economic Planning Studies to be included in the draft Unified Planning Assumptions and Study Plan. The CAISO may assess requests for Economic Planning Studies individually or in combination where such requests may have common or complementary effects on the CAISO Controlled Grid. The CAISO will perform a maximum of five High Priority Economic Planning Studies; however, the CAISO retains discretion to perform greater than five High Priority Economic Planning Studies should stakeholder requests or patterns of Congestion or anticipated Congestion so warrant.

24.2.3 Additional Planning Information.

24.2.3.1 Information Provided by Participating TOs.

In addition to any information that must be provided to the CAISO under the NERC Reliability Standards for Modeling, Data and Analysis (NERC MOD Standards), Participating TOs shall provide the CAISO on an annual or periodic basis in accordance with the schedule and procedures and in the form required by the Business Practice Manual any information and data reasonably required by the CAISO to perform the Transmission Planning Process, including, but not limited to: (1) modeling data for power flow, including reactive power, short-circuit and stability analysis; (2) a description of the total Demand to be served from each substation, including a description of any Energy efficiency programs reflected in the total Demand; (3) the amount of any interruptible Loads included in the total Demand (including conditions under which an interruption can be implemented and any limitations on the duration and frequency of interruptions); (4), a description of Generating Units to be interconnected to the Distribution System of the Participating TO, including generation type and anticipated Commercial Operation Date; (5) detailed power system models of their transmission systems that reflect transmission system changes, including equipment replacement not requiring approval by the CAISO; (6) Distribution System modifications; (7) transmission

network information, including line ratings, line length, conductor sizes and lengths, substation equipment ratings, circuits on common towers and with common rights-of-ways and cross-overs, special protection schemes, and protection setting information; and (8) Contingency lists.

24.2.3.2 Information Provided by Participating Generators.

In addition to any information that must be provided to the CAISO under the NERC Reliability Standards for Modeling, Data and Analysis (NERC MOD Standards), Participating Generators shall provide the CAISO on an annual or periodic basis in accordance with the schedule, procedures and in the form required by the Business Practice Manual any information and data reasonably required by the CAISO to perform the Transmission Planning Process, including, but not limited to (1) modeling data for short-circuit and stability analysis and (2) data, such as term, and status of any environmental or land use permits or agreements the expiration of which may affect that the operation of the Generating Unit.

24.2.3.3 Information Requested from Load Serving Entities.

In addition to any information that must be provided to the CAISO under the NERC Reliability Standards for Modeling, Data and Analysis (NERC MOD Standards), the CAISO shall solicit from Load Serving Entities through their Scheduling Coordinators information required by, or anticipated to be useful to, the CAISO in its performance of the Transmission Planning Process, including, but not limited to (1) long-term resource plans; (2) existing long-term contracts for resources and transmission service outside the CAISO Control Area; (3) resource capacity and Energy bid information received through requests for offers or similar solicitations; and (4) Demand Forecasts, including forecasted effect of Energy efficiency and Demand response programs.

24.2.3.4 Information Requested from Interconnected Control Areas, Sub-Regional Planning Groups and Electric Utility Regulatory Agencies.

In accordance with Section 24.8 of this Appendix EE, the CAISO shall obtain or solicit from interconnected Control Areas, regional and sub-regional planning groups within the WECC, the CPUC, the CEC, and Local Regulatory Authorities information required by, or anticipated to be useful to, the CAISO in its performance of the Transmission Planning Process, including, but not limited to (1) long-term transmission system plans; (2) long-term resource plans; (3) generation interconnection queue information; (4) Demand forecasts; and (5) any other data necessary for the development of power flow, short-circuit, and stability cases over the planning horizon of the CAISO Transmission Planning Process.

24.2.3.5 Obligation to Provide Updated Information.

If material changes to the information provided under Sections 24.2.3.1 and 24.2.3.2 of this Appendix EE occur during the annual Transmission Planning Process, the providers of the information must provide notice to the CAISO of the changes.

24.2.4 Unified Planning Assumptions and Study Plan.

24.2.4.1 Additional Projects and Data for Development of the Unified Planning Assumptions and Study Plan.

The CAISO will develop Unified Planning Assumptions and Study Plan using information and data received during the Request Window and under Section 24.2.3 of this Appendix EE. The CAISO will also use the following in the development of the Unified Planning Assumptions and Study Plan:

- (1) WECC base cases for the relevant planning horizon;
- (2) transmission upgrades and additions approved by the CAISO and scheduled to be energized within the planning horizon;

- (3) Location Constrained Resource Interconnection Facilities conditionally approved under Section 24.1.3.1(a) of this Appendix EE;
- (4) Network Upgrades identified pursuant to Section 25, Appendix U or Appendix W relating to the CAISO's Large Generator Interconnection Procedures and Appendix AA relating to the CAISO's Small Generator Interconnection Procedures;
- (5) operational solutions validated by the CAISO to address Local Capacity Area Resource requirements;
- (6) regulatory initiatives, as appropriate, including state regulatory agency initiated programs;
- (7) Energy Resource Areas or similar resource areas identified as high priority by the CPUC or CEC; and
- (8) results and analyses from Economic Planning Studies or other assessments that may have identified potentially needed transmission upgrades or additions performed in past CAISO Transmission Planning Process cycles.

24.2.4.2 General Scope of Unified Planning Assumptions and Study Plan.

The Unified Planning Assumptions and Study Plan shall, at a minimum, describe:

- (a) the planning data and assumptions to be used, to the maximum extent possible, as a base case for each technical study to be performed in the Transmission Planning Process cycle, including, but not limited to, those related to Demand Forecasts and distribution, generation capacity additions and retirements, and transmission system modifications;

- (b) a list of each technical study to be performed in the Transmission Planning Process cycle and a summary of the technical study's objective or purpose;
- (c) a description of any modifications to the planning data and assumptions developed as the general base case in Section 24.2.4.2(a) of this Appendix EE made in each technical study performed in the Transmission Planning Process cycle;
- (d) a description of the software tools, methodology and other criteria used in each technical study performed in the Transmission Planning Process cycle;
- (e) the identification of any entities directed to perform a particular technical study or portions of a technical study;
- (f) a proposed schedule for all stakeholder meetings to be held as part of the Transmission Planning Process cycle, and means for notification of any changes thereto, the location on the CAISO Website of information relating to the technical studies performed in the Transmission Planning Process cycle, and the name of a contact person at the CAISO for each technical study performed in the Transmission Planning Process cycle;
- (g) a list and description of each Economic Planning Study studied by the CAISO as a High Priority Economic Planning Study under Section 24.9 of this Appendix EE; and
- (h) to the maximum extent practicable, and where applicable, identify appropriate sensitivity analyses, including project or solution alternatives, to be performed as part of technical studies.

24.2.4.3 Preparation of Draft and Final Unified Planning Assumptions and Study Plan.

- (a) Following review of relevant information, the CAISO will prepare and post on the CAISO Website a draft Unified Planning Assumptions and Study Plan. The CAISO will issue a Market Notice announcing the availability such draft, soliciting comments, and scheduling a stakeholder conference(s) as required by Section 24.2.4.3(c) of this Appendix EE.
- (b) All comments from stakeholders on the draft Unified Planning Assumptions and Study Plan will be posted by the CAISO to the CAISO Website.
- (c) Subsequent to the posting of the draft Unified Planning Assumptions and Study Plan, the CAISO will conduct a minimum of one stakeholder meeting open to Market Participants, electric utility regulatory agencies, and other interested parties to review, discuss, and recommend modifications to the draft Unified Planning Assumptions and Study Plan. Additional stakeholder meetings, web conferences, or teleconferences may be scheduled as needed. All stakeholder meetings, web conferences, or teleconferences shall be noticed by Market Notice and such notice shall be posted to the CAISO Website.
- (d) Following the stakeholder conference(s) required by Section 24.2.4.2(c) of this Appendix EE, and under the schedule set forth in the Business Practice Manual, the CAISO will determine and publish to the CAISO Website the final Unified Planning Assumptions and Study Plan in accordance with the procedures set forth in the Business Practice Manual.

24.2.5 Development and Approval of Transmission Plan.

24.2.5.1 Technical Studies.

- (a) In accordance with the Unified Planning Assumptions and Study Plan and the procedures and deadlines in the Business Practice Manual, the CAISO will perform, or direct the performance by third parties of, technical studies and other assessments necessary for the Transmission Plan and Transmission Planning Process, post the preliminary results on the CAISO Website, conduct a minimum of one stakeholder conference, and provide an opportunity for comments of the preliminary results. Additional stakeholder meetings, web conferences, or teleconferences may be scheduled as needed. All stakeholder meetings, web conferences, or teleconferences shall be noticed by Market Notice and such notice shall be posted to the CAISO Website.
- (b) All technical studies, whether performed by the CAISO or third party under the direction of the CAISO, must utilize the Unified Planning Assumptions for the particular technical study to the maximum extent practical, and deviations from the Unified Planning Assumptions for the particular technical study must be documented in the preliminary and final results of each technical study. The CAISO will measure the results of the studies against NERC planning standards, WECC planning standards, and the CAISO Planning Standards, and other criteria established by the Business Practice Manual. After consideration of the comments received on the preliminary results, the CAISO will complete, or direct the completion of, the technical studies and post the final study results on the CAISO Website.

24.2.5.2 Development of Transmission Plan.

- (a) In accordance with the schedule and procedures in the Business Practice Manual, the CAISO will post a draft Transmission Plan. The CAISO will subsequently conduct a stakeholder conference regarding the draft Transmission Plan and solicit comments, consistent with the timelines and procedures set forth in the Business Practice Manual. Additional stakeholder meetings, web conferences, or teleconferences may be scheduled as needed. All stakeholder meetings, web conferences, or teleconferences shall be noticed by Market Notice and such notice shall be posted to the CAISO Website. After consideration of comments, the CAISO will post a final Transmission Plan to the CAISO Website.
- (b) The draft and final Transmission Plan may include, but is not limited to: (1) the results of technical studies performed under the Study Plan; (2) determinations, recommendations, and justifications for the need, according to Section 24.1 of this Appendix EE, for identified transmission upgrades and additions; (3) assessments of transmission upgrades and additions not proposed under Section 24.1 of this Appendix EE and for which need has not been formally determined by the CAISO Governing Board or management, as applicable, under Section 24.1 of this Appendix EE, but which have been identified by the CAISO as potential solutions to transmission needs studied during the Transmission Planning Process cycle; (3) results of Economic Planning Studies performed during the Transmission Planning Process cycle; and (4) an update on the status of transmission upgrades or additions previously approved by the CAISO, including identification of mitigation plans, if necessary, to address any potential delay in the anticipated completion of an approved transmission upgrade or addition.

- (c) The Transmission Plan may not include the results of certain technical studies performed as part of the Transmission Planning Process cycle identified in the Unified Planning Assumptions and Study Plan that were scheduled for completion after publication of the Transmission Plan for the Transmission Planning Process cycle.

24.2.5.3 Approval by the CAISO Governing Board.

The CAISO will present the Transmission Plan to the CAISO Governing Board at the first meeting of the year following the year in which the Transmission Plan is prepared. The Transmission Plan will be considered final once it has been presented to the CAISO Governing Board and will be posted on the CAISO Website. Transmission upgrades and additions for which CAISO Governing Board approval is required may be presented to the CAISO Governing Board for approval separate from presentation of the Transmission Plan.

24.3 Obligation to Construct Transmission Projects Included in Transmission Plan.

A Participating TO that has a PTO Service Territory shall be obligated to construct all transmission additions and upgrades that are determined by the CAISO Governing Board or management, as applicable, to be needed in accordance with the requirements of Section 24 of this Appendix EE, not including conditional approvals and determinations of need under Section 24.1.3.1(a), and which: (1) are additions or upgrades to transmission facilities that are located within its PTO Service Territory, unless (a) it does not own the facility being upgraded or added and neither terminus of such facility is located within its PTO Service Territory or (b) it does not own the facility being upgraded or added and the Project Sponsor is a Participating TO that elects to construct the transmission upgrade; or (2) are additions to existing transmission facilities or upgrades to existing transmission facilities that it owns, that are part of the CAISO Controlled Grid, and that are located outside of its PTO Service Territory, unless the joint-ownership arrangement, if any, does not permit. A Participating TO's obligation

to construct such transmission additions and upgrades shall be subject to: (1) its ability, after making a good faith effort, to obtain all necessary approvals and property rights under applicable federal, state, and local laws and (2) the presence of a cost recovery mechanism with cost responsibility assigned in accordance with Section 24.7 of the CAISO Tariff. The obligations of the Participating TO to construct such transmission additions or upgrades will not alter the rights of any entity to construct and expand transmission facilities as those rights would exist in the absence of a TO's obligations under this CAISO Tariff or as those rights may be conferred by the CAISO or may arise or exist pursuant to this CAISO Tariff.

24.4 Participating TO Study Obligation.

The Participating TO constructing or expanding facilities in accordance with Section 24.3 of this Appendix, will be directed by the CAISO to coordinate with the Project Sponsor or Participating TO(s) with PTO Service Territories in which the transmission upgrade or addition will be located, as appropriate, and other Market Participants to perform any study or studies necessary, including a Facility Study, to determine the appropriate facilities to be constructed in accordance with the CAISO Transmission Planning Process and the terms set forth in the TO Tariff.

24.5 Operational Review.

The CAISO will perform an operational review of all facilities studied as part of the CAISO Transmission Planning Process that are proposed to be connected to, or made part of, the CAISO Controlled Grid to ensure that the proposed facilities provide for acceptable operating flexibility and meet all its requirements for proper integration with the CAISO Controlled Grid. If the CAISO finds that such facilities do not provide for acceptable operating flexibility or do not adequately integrate with the CAISO Controlled Grid, the CAISO shall coordinate with the Project Sponsor and, if different, the Participating TO with the PTO Service Territory in which the facilities will be located to reassess and redesign the facilities required to be constructed. Transmission upgrades or additions that do not provide acceptable operating flexibility or do not adequately integrate with the CAISO Controlled Grid cannot be included in the CAISO Transmission Plan or approved by CAISO management or the CAISO Governing Board, as applicable.

24.6 State and Local Approval and Property Rights.

24.6.1 The Participating TO obligated to construct facilities under this Section 24 must make a good faith effort to obtain all approvals and property rights under applicable federal, state and local laws that are necessary to complete the construction of the required transmission additions or upgrades. This obligation includes the Participating TO's use of eminent domain authority, where provided by state law.

24.6.2 If the Participating TO cannot secure any such necessary approvals or property rights and consequently is unable to construct a transmission addition or upgrade found to be needed in accordance with Section 24.1 of this Appendix, it shall promptly notify the CAISO and the Project Sponsor, if any, and shall comply with its obligations under the TO Tariff to convene a technical meeting to evaluate alternative proposals. The CAISO shall take such action as it reasonably considers appropriate, in coordination with the Participating TO, the Project Sponsor, if any, and other affected Market Participants, to facilitate the development and evaluation of alternative proposals including, where possible, conferring on a third party the right to build the transmission addition or upgrade as set forth in Section 24.6.3 of this Appendix.

24.6.3 Where the conditions of Section 24.6.2 of this Appendix have been satisfied and it is possible for a third party to obtain all approvals and property rights under applicable federal, state and local laws that are necessary to complete the construction of transmission additions or upgrades required to be constructed in accordance with this CAISO Tariff (including the use of eminent domain authority, where provided by state law), the CAISO may confer on a third party the right to build the transmission addition or upgrade, which third party shall enter into the Transmission Control Agreement in relation to such transmission addition or upgrade.

24.7 WECC and Regional Coordination.

The Project Sponsor will have responsibility for completing any applicable WECC requirements and rating study requirements to ensure that a proposed transmission addition or upgrade meets regional planning requirements. The Project Sponsor may request the Participating TO to perform this coordination on behalf of the Project Sponsor at the Project Sponsor's expense.

24.8 Regional and Sub-Regional Planning Process.

The CAISO will be a member of the WECC and other applicable regional or sub-regional organizations and participate in WECC's operation and planning committees, and in other applicable regional and sub-regional coordinated planning processes.

24.8.1 Scope of Regional or Sub-Regional Planning Participation.

The details of the CAISO's participation in regional and sub-regional planning processes are set forth in the Business Practice Manual. At a minimum, the CAISO shall be required to:

- (a) solicit the participation, whether through sub-regional planning groups or individually, of all interconnected Control Areas in the development of the Unified Planning Assumptions and Study Plan and in reviewing the results of technical studies performed as part of the CAISO's Transmission Planning Process in order to:
 - (1) coordinate, to the maximum extent practicable, planning assumptions, data and methodologies utilized by the CAISO, regional and sub-regional planning groups or interconnected Control Areas;
 - (2) ensure transmission expansion plans of the CAISO, regional and sub-regional planning groups or interconnected Control Areas are simultaneously feasible and seek to avoid duplication of facilities.
- (b) coordinate with regional and sub-regional planning groups regarding the entity to perform requests for Economic Planning Studies or other Congestion related studies;
- (c) transmit to applicable regional and sub-regional planning groups or interconnected Control Areas information on technical studies performed as part of the CAISO Transmission Planning Process;

- (d) post on the CAISO Website links to the planning activities of applicable regional and sub-regional planning groups or interconnected Control Areas.

24.8.2 Limitation on Regional Activities.

Neither the CAISO nor any Participating TO nor any Market Participant shall take any position before the WECC or a regional organization that is inconsistent with a binding decision reached through an arbitration proceeding pursuant to Section 13 of the CAISO Tariff.

24.9 Economic Planning Studies.

24.9.1 Congestion Data Summary.

In accordance with the schedule and procedures set forth in the Business Practice Manual, the CAISO shall post on the CAISO Website a Congestion Data Summary.

24.9.2 High Priority Economic Planning Studies.

High Priority Economic Planning Studies shall be performed in accordance with the standards and procedures established in the Business Planning Manual. Market Participants may conduct Economic Planning Studies that have not been designated as High Priority Economic Planning Studies at their own expense and may submit such studies for consideration in the development of the Transmission Plan when the CAISO provides notice of the stakeholder meeting regarding technical study results pursuant to Section 24.2.5.2 of this Appendix EE.

PART B. – DEFINITIONS

CAISO Planning Standards

Reliability Criteria that: (1) address specifics not covered in the NERC and WECC planning standards; (2) provide interpretations of the NERC and WECC planning standards specific to the CAISO Controlled Grid; and (3) identify whether specific criteria should be adopted that are more stringent than the NERC and WECC planning standards.

CEC

The California Energy Commission or its successor.

Congestion Data Summary

A report issued by the CAISO on the schedule set forth in the Business Practice Manual that sets forth historic Congestion on the CAISO Controlled Grid.

Critical Energy Infrastructure Information (CEII)

Critical Energy Infrastructure Information shall have the meaning given the term in the regulations of FERC at 18 C.F.R. § 388.12, et seq.

Economic Planning Study

A study performed to provide a preliminary assessment of the potential cost effectiveness of mitigating specifically identified Congestion.

High Priority Economic Planning Study

An Economic Planning Study performed by the CAISO for inclusion in the Transmission Plan and for which the CAISO assumes cost responsibility.

Long Term Congestion Revenue Right (Long Term CRR)

A Congestion Revenue Right differentiated by season and time-of-use period (on-peak and off-peak) with a term of ten years.

Merchant Transmission Facility

A transmission facility or upgrade that is part of the CAISO Controlled Grid and whose costs are paid by a Project Sponsor that does not recover the cost of the transmission investment through the CAISO's Access Charge or WAC or other regulatory cost recovery mechanism.

NERC Reliability Standards for Modeling, Data and Analysis (NERC MOD Standards)	A set of NERC Reliability Standards applicable to the transmission planning process.
Planning Standards Committee	The committee appointed under Section 24.2.1.
Request Window	The period of time as set forth in the Business Practice Manual during which transmission additions or upgrades, requests for Economic Planning Studies, and other transmission related information is submitted to the CAISO in accordance with Section 24.2.2 of Appendix EE.
Study Plan	The plan to be developed pursuant to Section 24.4.3 of Appendix EE, which sets forth the technical studies to be performed during the annual Transmission Planning Process.
Transmission Plan	The report prepared by the CAISO on annual basis pursuant to Section 24 of Appendix EE, which documents the outcome of the Transmission Planning Process as defined in the Study Plan.
Transmission Planner	A designation by NERC regarding responsibility to perform specified transmission planning functions in accordance with the NERC Reliability Standards.
Transmission Planning Process	The process by which the CAISO assesses the CAISO Controlled Grid as set forth in Section 24 of Appendix EE.
Unified Planning Assumptions	The assumptions to be developed pursuant to Section 24.4.3 of Appendix EE and used, to the maximum extent possible, in performing technical studies identified in the Study Plan as part of the annual Transmission Planning Process.