California ISO Conformed Tariff as of September 16, 2004

IMPORTANT NOTICE:

The Tariff is current through September 16, 2004. Currently effective language from Tariff Amendments and compliance filings which FERC has approved is shown in clean copy. Pending language from compliance filings that FERC has not ruled on as of September 16, 2004, but whose proposed effective date has already arrived, is shown in highlight.

Note that where such pending compliance filing language will supersede currently approved language, it will be necessary to consult previous versions of the Tariff to see the full text of the language superseded by the highlighted pending language.

PLEASE NOTE that this Conformed Tariff DOES NOT REFLECT THE MRTU PHASE 1B PROVISIONS WHICH WENT INTO EFFECT ON OCTOBER 1, 2004. It is updated ONLY through September 16, and thus ONLY reflects tariff language effective as of that date. The ISO is in the process of preparing a Conformed Tariff updated to reflect the implementation of MRTU Phase 1B, which will be posted on the ISO website as soon as possible during the week beginning October 4, 2004. Until that time, the MRTU supplementary Tab (Tab 1) posted below contains all the MRTU Phase 1B provisions now in effect.

The Tariff does not include Tariff Amendments submitted to the Commission but not yet approved (e.g. Amendments 62, 63, etc.).

This version updates the August 10, 2004 version of the Conformed Tariff to reflect:

- The approval of Amendment 61 by FERC on August 17, 2004 (see Order on Amendment 61 at 108 FERC ¶ 61,193) with modifications as ordered by FERC and reflected in the ISO's Amendment 61 Compliance filing made on September 16, 2004. The new Amendment 61 language can be found on pages 204A, 204A.01, 205 and 205A; those changes proposed in the September 16 compliance filing are shown in highlight. For the specific content of the changes, compare the current Conformed Tariff to the August 10, 2004 version http://www.caiso.com/docs/2001/01/22/200101221229006730.html and review the blackline changes shown in Attachment B to the ISO's Amendment 61 filing of June 18, 2004, and Attachment C to the ISO's Amendment 61 Compliance Filing of September 16, 2004, available at the Tariff Amendments section of the ISO website;

- The acceptance by FERC, on September 15, 2004, of the tariff sheets comprising the new Dynamic Scheduling Protocol proposed by the ISO in its Amendment 59 Compliance Filing made on June 29, 2004 (see Letter Order issued September 15, 2004 in Docket ER04-793-001). The Dynamic Scheduling Protocol (DSP) was shown in the previous version of the Conformed Tariff in highlight; now that it has been accepted, the highlighting has been removed

Following the Tariff itself, five tabbed supplementary sections (corresponding to the ISO's MRTU filings, the Amendment 55 Oversight & Investigations filings, the December 15, 2003 Must-Offer Obligation compliance filing, the Amendment 60 provisions on Allocation of Minimum Load Costs, and new Section 5.11.6.2 on Security Constrained Unit Commitment (SCUC) applications, respectively) are provided which include language which is not effective as of September 16, 2004. Tariff language that is approved but not yet effective is included in the clean copy of these supplementary sections; Tariff language from pending compliance filings is shown in highlight.

The current version of Tab 1 reflects changes to the August 10, 2004, version made as a result of the approval of Amendment 58 (see Order at 108 FERC ¶ 61,141) and the approval of the ISO's November 21, 2003, Compliance Filing to Amendment 54 (see Order on Rehearing and Compliance at 108 FERC ¶

61,142) with modifications as ordered by FERC and reflected in the ISO's related Amendment 54 and Amendment 58 Compliance Filings made on September 7, 2004. The newly approved Amendment 54 and Amendment 58 language can be found in Tab 1, on pages 109, 184E, 184E.01, 213, 213.00, 247.01, 247.02, 247A, 247B, 247C, 247C.00, 247C.01, 247D, 308, 352, 352A, 565, 694C, 694D, 694E, 694G, 694H, 879, 880, 881, 882, 883, 883A, 884, and 884A; those changes proposed in the September 7 compliance filings are shown in highlight. For the specific content of these changes, consult Attachment B to the ISO's November 21, 2003, filing, Attachment B to the ISO's March 2, 2004, Amendment 58 filing, and the attachments labeled "Attachment B" to the ISO's Amendment 54 and Amendment 58 Compliance Filings of September 7, 2004, available at the Tariff Amendments section of the ISO website. Note that proposed language from the November 21, 2003 compliance filing was reflected in highlight in previous versions of Tab 1; where that language has been approved, the highlighting has been removed.

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1. DEFINITIONS AND INTERPRETATION.

1.1 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.

1.2 In this ISO Tariff "includes" or "including" shall mean "including without limitation".

1.3 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.

2. ISO OPERATIONS.

2.1 Access to the ISO Controlled Grid.

2.1.1 Open Access.

The ISO shall, subject to Sections 2.1.2 and 2.1.3, 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.

2.1.2 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).

2.1.3 Facilities Financed by Local Furnishing Bonds or Other Tax-Exempt Bonds.

2.1.3.1 This Section 2.1.3 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.

2.1.3.2 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 2.1.3.1 and shall keep the ISO fully informed of any changes necessary to that ISO Protocol from time to time.

2.1.3.3 The ISO shall implement the ISO Protocol referred to in Section 2.1.3.1 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.

2.2 Scheduling.

2.2.1 Scheduling Responsibilities and Obligations.

The provisions of this Section 2.2 shall govern the ISO's scheduling of Energy and Ancillary Services on the ISO Controlled Grid and Congestion Management. 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.

2.2.2 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 2.2.7.2, 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 7.2.6; and

(f) if necessary, make mandatory adjustments to Schedules in accordance with the Congestion Management procedures.

2.2.3 Scheduling Coordinator Certification.

The ISO shall accept Schedules and bids for Energy and Ancillary Services only from Scheduling Coordinators which it has certified in accordance with Section 2.2.4 as having met the requirements of this Section 2.2.3. Scheduling Coordinators scheduling Ancillary Services shall additionally meet the requirements of Section 2.5.6.

2.2.3.1 Each Scheduling Coordinator shall:

(a) demonstrate to the ISO's reasonable satisfaction that it is capable of performing the functions of a Scheduling Coordinator under this ISO Tariff including (without limitation) the functions specified in Sections 2.2.6 and 2.2.7 and that it is capable of complying with the requirements of all ISO Protocols;

(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 for which it is submitting bids under this ISO 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 ISO's reasonable satisfaction that it meets the financial criteria set out in Section 2.2.3.2;

(f) enter into an SC Agreement with the ISO; and

(g) provide NERC tagging data.

2.2.3.2 The creditworthiness requirements in this section apply to the ISO's acceptance of Schedules and to all transactions in an ISO Market. Each Scheduling Coordinator, UDC or MSS shall either maintain an Approved Credit Rating (which may differ for different types of transactions with the ISO) or provide in favor of the ISO one of the following forms of security for an amount to be determined by the Scheduling Coordinator, UDC or MSS and notified to the ISO under Section 2.2.7.3:

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

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

(c) an unconditional and irrevocable guarantee by a company which has and maintains an Approved Credit Rating;

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

(e) a certificate of deposit in the name of the ISO from a financial institution designated by the ISO; or

(f) a payment bond certificate in the name of the ISO from a financial institution designated by the ISO.

Letters of credit, guarantees, surety bonds, payment bond certificates, escrow agreements and certificates of deposit must cover all applicable outstanding and estimated liabilities under Section 2.2.7.3 and shall be in such form as the ISO may reasonably require from time to time by notice to Scheduling Coordinators, UDCs or MSSs. A Scheduling Coordinator, UDC or MSS which does not maintain an Approved Credit Rating shall be subject to the limitations on trading set out in Section 2.2.7.3. Notwithstanding anything to the contrary in the ISO Tariff, a Scheduling Coordinator or UDC that had an Approved Credit Rating on January 3, 2001, and is an Original Participating Transmission Owner or is a Scheduling Coordinator for an Original Participating Transmission Owner shall not be precluded by Section 2.2.7.3 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.

2.2.3.3 Review of Creditworthiness.

The ISO may review the creditworthiness of any Scheduling Coordinator, UDC or MSS which delays or defaults in making payments due under the ISO Tariff and, as a consequence of that review, may require such Scheduling Coordinator, UDC or MSS, whether or not it has (or is deemed to have) an Approved Credit Rating, to provide credit support in the form of:

(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; or

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

The ISO may require the Scheduling Coordinator, UDC or MSS to maintain such credit support for at least one (1) year from the date of such delay or default.

2.2.4 Certification Procedure.

2.2.4.1 The ISO shall certify Scheduling Coordinators in accordance with the following application procedure. An SC Applicant shall furnish the ISO with the following:

(a) a completed SC Application Form; and

(b) a non-refundable application fee set by the ISO Governing Board.

The application fee will cover the reasonable costs associated with processing the application, including credit reference verification and the provision of documentation.

2.2.4.2 Application.

(a) The SC Application Form must be sent to the ISO in accordance with Section 20.1, at least sixty (60) days in advance of the date on which the SC Applicant proposes to commence operating as a Scheduling Coordinator.

(b) The ISO shall acknowledge receipt of the SC Application Form in writing promptly after receiving it.

(c) The ISO shall review the application and may request additional information, clarifications or further documentation from the SC Applicant that the ISO reasonably considers may be relevant in determining whether the SC Applicant meets the eligibility requirements of Section 2.2.3 within 14 days after receiving the SC Application Form.

(d) If the SC Applicant fails to respond appropriately to any request by the ISO pursuant to subsection (c), within seven (7) days or such longer period as the ISO may agree, the ISO may reject the application.

(e) The ISO will notify the SC Applicant in writing whether its application has been accepted or rejected and, if rejected, will give a written explanation of the reasons for the rejection within 14 days after the SC Applicant has provided all of the additional information requested by the ISO pursuant to subsection (c).

(f) The SC Applicant shall become a Scheduling Coordinator when, following acceptance of its Application, it has entered into an SC Agreement with the ISO and has met the requirements of Section 2.2.3.2.

2.2.4.3 The SC Applicant may within twenty-eight (28) days following rejection of its application, appeal in writing that rejection to the ISO Governing Board setting out the grounds for the appeal. The ISO Governing Board will hear the appeal on and present an oral decision within thirty-five (35) days of the date the appeal notice is served on the ISO Governing Board in accordance with Section 20.1. The ISO Governing Board will notify the SC Applicant in writing of its decision within seven (7) days of hearing the appeal.

2.2.4.4 If the ISO Governing Board rejects the application on appeal then the SC Applicant may appeal under the ISO ADR Procedure. The ISO shall agree to mediation under Section 13.2 if the SC Applicant so requests.

2.2.4.5 Termination of Service Agreement.

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

(i) if the Scheduling Coordinator no longer meets the requirements for eligibility set out in Section 2.2.3 and fails to remedy the default within a period of seven (7) days after the ISO has given written notice of the default;

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

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

(b) by the Scheduling Coordinator on sixty (60) days written notice to the ISO, provided that such notice shall not be effective to terminate the SC Agreement until the Scheduling Coordinator has complied with all applicable requirements of Section 2.2.5.

The ISO shall, following termination of an SC Agreement and within thirty (30) days of being satisfied that no sums remain owing by the Scheduling Coordinator under the ISO Tariff, return or release to the Scheduling Coordinator, as appropriate, any money or credit support provided by such Scheduling Coordinator to the ISO under Section 2.2.3.2.

2.2.4.5.1 Pending acceptance of termination of service pursuant to Section 2.2.4.6.1 by FERC, the ISO will suspend the certification of a Scheduling Coordinator which has received a notice of termination under Section 2.2.4.5(a) and the Scheduling Coordinator will not be eligible to submit Schedules and bids for Energy and Ancillary Services to the ISO.

2.2.4.6 Notification of Termination. The ISO shall, promptly after providing written notice of default to a Scheduling Coordinator as specified in Section 2.2.4.5(a), notify the Scheduling Coordinators that could be required to represent End Use Eligible Customers of the Scheduling Coordinator under Section 2.2.4.7.2 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 2.2.4.5, 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 SC Agreement will automatically remove the Scheduling Coordinator's certification under Section 2.2.4 and Section 2.5.6.

2.2.4.6.1 Filing of Notice of Termination. Any notice of termination given pursuant to Section 2.2.4.5 shall also be filed by the ISO with FERC.

2.2.4.7 Continuation of Service on Termination.

2.2.4.7.1 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 2.2.4.7.2.

2.2.4.7.2 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 2.2.4.5.1, Eligible Customers of the defaulting Scheduling Coordinators shall be assigned to all Scheduling Coordinators on the list established pursuant to Section 2.2.4.7.2 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 2.2.4.7.1, 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.

2.2.5 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.

2.2.6 Responsibilities of a Scheduling Coordinator.

Each Scheduling Coordinator shall be responsible for:

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

2.2.6.2 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;

2.2.6.3 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;

2.2.6.4 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;

2.2.6.5 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;

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

2.2.6.7 Ancillary Services. Providing Ancillary Services in accordance with Section 2.5;

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

2.2.6.9 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;

2.2.6.10 Interruptible Imports. Identifying any Interruptible Imports included in its Schedules; and

2.2.6.11 Participating Intermittent Resources. Submitting Schedules consistent with the ISO Protocols.

2.2.7 Operations of a Scheduling Coordinator.

2.2.7.1 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.

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

2.2.7.3 Limitation on Trading. A Scheduling Coordinator, UDC or MSS that does not maintain an Approved Credit Rating, as defined with respect to either payment of the Grid Management Charge, or payment of other charges, shall maintain security in accordance with Section 2.2.3.2. For the avoidance of doubt, the ISO Security Amount is intended to cover the entity's outstanding and estimated liability for either (i) Grid Management Charge; and/or (ii) Imbalance Energy, Ancillary Services, Grid Operations Charge, Wheeling Access Charge, High Voltage Access Charge, Transition Charge, Usage Charges, and FERC Annual Charges. Each Scheduling Coordinator, UDC or MSS required to provide an ISO Security Amount under Section 2.2.3.2 shall notify the ISO of the initial ISO Security Amount (separated into amounts securing payment of the Grid Management Charge and amounts securing payments of other charges) that it wishes to provide at least fifteen (15) days in advance and shall ensure that the ISO has received such ISO Security Amount prior to the date the Scheduling Coordinator commences trading or the UDC or MSS commences receiving bills for the High Voltage

Access Charge and Transition Charge. A Scheduling Coordinator, UDC or MSS may at any time increase its ISO Security Amount by providing additional guarantees or credit support in accordance with Section 2.2.3.2. A Scheduling Coordinator, UDC or MSS may reduce its ISO Security Amount by giving the ISO not less than fifteen (15) days notice of the reduction, provided that the Scheduling Coordinator, UDC or MSS is not then in breach of this Section 2.2.7.3. The ISO shall release, or permit a reduction in the amount of, such guarantees or other credit support required to give effect to a permitted reduction in the ISO Security Amount as the Scheduling Coordinator, UDC or MSS may select.

Following the date on which a Scheduling Coordinator commences trading, the Scheduling Coordinator shall not be entitled to submit a Schedule to the ISO and the ISO may reject any Schedule submitted if, at the time of submission, the Scheduling Coordinator's ISO Security Amount is exceeded by the Scheduling Coordinator's estimated aggregate liability for (i) Grid Management Charge and/or Imbalance Energy, Ancillary Services, Grid Operations Charge, Wheeling Access Charge, Usage Charges, and FERC Annual Charges on each Trading Day for which Settlement has not yet been made in accordance with Section 11.3.1 and the Scheduling Coordinator's estimated liability for High Voltage Access Charge and Transition Charge for which Settlement has not yet been made in accordance with Section 11.3. The ISO shall notify a Scheduling Coordinator if at any time such outstanding liabilities exceed 90% of the relevant portion of the ISO Security Amount. For the purposes of calculating the Scheduling Coordinator’s estimated aggregate liability, the estimate 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, appropriately adjusted to reflect recent market prices and trends, or other available information for individual Scheduling Coordinators.

Following the date on which a UDC or MSS commences operation, the UDC's or MSS's Scheduling Coordinator shall not be entitled to submit a Schedule to the ISO and the ISO may reject any Schedule submitted if, at the time of submission, the UDC's or MSS's ISO Security Amount is exceeded by the UDC's or MSS's estimated aggregate liability for Grid Management Charge, and/or High Voltage Access Charges and Transition Charges for which Settlement has not yet been made in accordance with Section 11.3. The ISO shall notify a UDC or MSS if at any time such outstanding liabilities exceed 90% of the relevant portion of the ISO Security Amount. For the purposes of estimating the UDC's or MSS's aggregate liability for High Voltage Access Charges and Transition Charges, the UDC's or MSS's liability shall be equal to the billed Demand use (in MWh) for a month in the UDC's or MSS's Service Area (including exports from the Service Area) multiplied by the ISO's estimated High Voltage Access Charge and Transition Charge for that month, as such estimated cost is notified by the ISO to UDCs and MSSs from time to time.

2.2.7.4 The ISO shall notify the relevant Scheduling Coordinator if it rejects a Schedule under Section 2.2.7.3 in which event the Scheduling Coordinator shall not be entitled to submit any further Schedules until it has demonstrated to the ISO's satisfaction that its ISO Security Amount has been increased sufficiently to avoid the limit on trading imposed under Section 2.2.7.3 from being exceeded.

2.2.7.5 The ISO may restrict, or suspend a Scheduling Coordinator’s right to Schedule or require the Scheduling Coordinator to increase its ISO Security Amount if at any time such Scheduling Coordinator’s liability for Imbalance Energy is determined by the ISO to be excessive by comparison with the likely cost of the amount of Energy scheduled by the Scheduling Coordinator.

2.2.7.6 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 or special operating agreement related to the operation of dynamic functionality.

2.2.8 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.

2.2.8.1 Preferred Schedule. A Preferred Schedule shall be 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 2.5.10 and, where they elect to self-provide Ancillary Services pursuant to Section 2.5.20.1, an Ancillary Service schedule meeting the requirements set forth in Section 2.5.20.6. The Preferred Schedule shall also include an indication of which resources (Generation or Load) if any may be adjusted by the ISO to eliminate Congestion. On receipt of the Preferred Schedule in the Day-Ahead scheduling process, 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 2.2.11.3.4. If the ISO notifies a Scheduling Coordinator that there will be no Congestion on the ISO Controlled Grid and, subject to Section 2.2.11.3.4, the Preferred Schedule shall become that Scheduling Coordinator's Final Schedule.

2.2.8.2 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.

2.2.8.3 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. 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 2.2.11.3.4.

2.2.8.4 Final Schedules. If the ISO notifies a Scheduling Coordinator that there will be no Congestion on the ISO Controlled Grid, the Revised Schedule shall become that Scheduling Coordinator's Final Schedule. If no Scheduling Coordinator submits any changes to the Suggested Adjusted Schedules, all of the Suggested Adjusted Schedules shall become the Final Schedules. The Final Schedules shall serve as the basis for Settlement between the ISO and each Scheduling Coordinator.

2.2.9 [Not Used]

2.2.10 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:

2.2.10.1 Scheduled Line Outages. Scheduled transmission line Outages;

2.2.10.2 [Not Used]

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

2.2.10.4 Advisory Demand Forecasts. Advisory Demand Forecasts by location;

2.2.10.5 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;

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

2.2.10.7 [Not Used]

2.2.10.8 [Not Used]

2.2.11 Information to Be Submitted by Scheduling Coordinators to the ISO.

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:

2.2.11.1 For Demand:

2.2.11.1.1 Designated Location Code. For all Demand the Location Code of the Take-Out Point;

2.2.11.1.2 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;

2.2.11.1.3 Flexibility. Whether the Preferred Schedule is flexible for adjustment to eliminate Congestion;

2.2.11.1.4 Adjustment Bids. The MW and $/MWh values representing the Adjustment Bid curve for any Dispatchable Load.

2.2.11.2 For Generation:

2.2.11.2.1 Location of Generating Units. The Location Code of all Generating Units scheduled, if applicable, or the source Control Area and Scheduling Point;

2.2.11.2.2 Quantity Scheduled. The aggregate quantity (in MWh) being scheduled from each Generating Unit and System Resource;

2.2.11.2.3 Notification of Flexibility. Notification of whether the Preferred Schedule is flexible for adjustment to eliminate Congestion;

2.2.11.2.4 **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;

2.2.11.2.5 **Operating Characteristics.** Operating characteristics for each Generating Unit and System Resource for which an Adjustment Bid has been submitted; and

2.2.11.2.6 **Must-Take/Must-Run Generation.** Identification of all scheduled Generating Units that are Regulatory Must-Take Generation or Regulatory Must-Run Generation.

2.2.11.3 **For deliveries to/from other Scheduling Coordinators:**

2.2.11.3.1 **Identification Code.** Identification Code of Scheduling Coordinator to which Energy is provided or from which Energy is received;

2.2.11.3.2 **Quantity of Energy.** Quantity (in MWh) of Energy being received or delivered;

2.2.11.3.3 **Zone.** The Zone within which Energy is deemed to be provided by one Scheduling Coordinator to another under the Inter-Scheduling Coordinator Energy Trades.

2.2.11.3.4 **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 in accordance with the procedures detailed in the ISO Protocols.

2.2.11.3.5 The Generating Unit or Dispatchable Load that the source or recipient of Energy traded.

2.2.11.3.6 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.

2.2.11.4 **For Self-Provided Ancillary Services:** Scheduling Coordinators electing to self-provide Ancillary Services shall supply the information referred to in Section 2.5.20.5 in relation to each Ancillary Service to be self-provided.

2.2.11.5 **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 2.5.3.2 to cover such Interruptible Imports or to purchase such Operating Reserve from the ISO.

2.2.12 **Timing of Day-Ahead Scheduling.**

2.2.12.1 The ISO may in its sole discretion waive the timing requirements of this Section 2.2 where necessary to preserve System Reliability. The ISO may also waive the timing requirements of Section 2.2 where, because of error or delay, the ISO is unable to meet the timing requirements. Any such waiver shall be published on WEnet.

2.2.12.2 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".

2.2.12.2.1 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 2.2.12.2 (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.

2.2.12.2.2 ***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 SC shall be entitled to any payment from any source for RMR Energy that is not scheduled as required by this Section 2.2.12.2.2. 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 SC 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.

2.2.12.2.2.1 [not used]

2.2.12.2.3 ***RMR Market Option*** – This Section 2.2.12.2.3 provides how an Applicable RMR Owner electing the RMR Market Option shall satisfy its obligation to deliver RMR Energy.

2.2.12.2.3.1 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 SC 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 SC 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 SC 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 SC shall be entitled to any payment from any source for RMR Market Energy that is not bid and scheduled as required by this Section 2.2.12.2.3. 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 SC 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.

2.2.12.2.3.2 If the Applicable RMR SC'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.

2.2.12.2.3.2.1 The Applicable RMR SC'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 2.2.12.2.3.2 but was not awarded in such power exchange markets for such hour. If the Preferred Hour-Ahead Schedule of the Applicable RMR SC 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 SC will allow the RMR Unit to be redispatched for that hour.

2.2.12.2.3.3 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 2.2.12.2.3, 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 SC shall be entitled to any payment from any source for RMR Market Energy that is not bid and scheduled as required by this Section 2.2.12.2.3.

2.2.12.2.4 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 SC 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.

2.2.12.2.5 [not used]

2.2.12.3 **Demand Information.** By 6:00 a.m. on the day preceding the Trading Day, each Scheduling Coordinator shall provide to the ISO a Demand Forecast specified by UDC Service Area for which it will schedule deliveries for each of the Settlement Periods of the following Trading Day. The ISO shall aggregate the Demand information by UDC Service Area and transmit the aggregate Demand information to each UDC serving such aggregate Demand.

2.2.12.4 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.

2.2.12.5 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.

2.2.12.6 **ISO Analysis of Preferred Schedules.** On receipt of the Preferred Schedules, the ISO will analyze the Preferred Schedules of Applicable RMR SCs to determine the compatibility of such Preferred Schedules with the RMR Dispatch Notices. 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 2.2.11.3.4. 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 2.2.11.3.4, the Preferred Schedules shall become the Final Schedules and the ISO shall notify Scheduling Coordinators accordingly.

2.2.12.7 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.

2.2.12.8 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 2.2.11.3.4.

2.2.12.8.1 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 2.2.11.3.4, the Revised Schedules and any unamended

Preferred Schedules shall become Final Day-Ahead Schedules and the ISO shall notify Scheduling Coordinators accordingly.

2.2.12.8.2 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 and the ISO Protocols to develop the Final Day-Ahead Schedules.

2.2.13 Timing of Hour-Ahead Scheduling.

2.2.13.1 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.

2.2.13.1.1 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.

2.2.13.1.2 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.

2.2.13.2 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.

2.2.13.2.1 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.

2.2.13.2.2 Congestion Management Provisions for Final Hour-Ahead Schedules. If the ISO identifies Congestion, it shall use the Congestion Management provisions of Section 7.2 of this ISO Tariff and the ISO Scheduling Protocol to develop the Final Hour-Ahead Schedules.

2.2.13.2.3 [Not Used]

2.2.13.3 Final Hour-Ahead Schedules. The ISO shall inform each Scheduling Coordinator of its responsibilities to provide Ancillary Services in accordance with Section 2.5.21. 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:

2.2.13.3.1 Generation.

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

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

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

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

2.2.13.3.1.5 [Not Used]

2.2.13.3.2 Load.

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

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

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

2.2.13.4 Usage Charges. The ISO shall notify each Scheduling Coordinator of the applicable Usage Charge calculated in accordance with Section 7.3.

2.2.14 Communications.

2.2.14.1 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. The ISO will establish the back-up communication procedures as part of the ISO Protocols.

2.2.14.2 Any Generation or Demand that is available for Dispatch must be capable of responding to ISO Dispatch instructions through a direct computer link or other means in accordance with the ISO Protocol on Dispatch.

2.2.15 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 2.2.3 hereof and the accuracy of information submitted to the ISO pursuant to Section 2.2.11.

2.2.16 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.

2.2.17 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. Settlement with Participating Intermittent Resources that meet the scheduling obligations established in the ISO Protocols shall be as provided in this ISO Tariff. 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, or that fails to meet the scheduling obligations established in the ISO Protocols, 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).

2.3 System Operations under Normal and Emergency Operating Conditions.

2.3.1 ISO Control Center Operations.

2.3.1.1 ISO Control Center.

2.3.1.1.1 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.

2.3.1.1.2 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.

2.3.1.1.3 ISO Control Center Authorities. The ISO shall have full authority, subject to Section 2.3.1.2, to direct the operation of the facilities referred to in Section 2.3.1.1.2 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;

(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 and System Resources that are selected to provide Ancillary Services and Imbalance Energy;

(f) dispatch Loads through direct Load control or other means at the ISO's discretion that are curtailable as an Ancillary Service; and

(g) procure Supplemental Energy.

2.3.1.1.4 **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 2.3.3.

2.3.1.1.5 **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.

2.3.1.1.6 The ISO shall be the WECC reliability coordinator for the ISO Controlled Grid.

2.3.1.2 Market Participant Responsibilities.

2.3.1.2.1 Comply with Operating Orders Issued. With respect to this Section 2.3.1.2, all Market Participants within the ISO Control Area shall comply fully and promptly with the ISO's operating orders, unless such operation would impair public health or safety. 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.

2.3.1.2.2 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 Protocols.

2.3.1.3 Operating Reliability Criteria.

2.3.1.3.1 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.

2.3.1.3.2 The ISO may establish planning and Operating Reserve criteria more stringent than those established by WECC and NERC or revise the Local Reliability Criteria subject to and in accordance with the provisions of the TCA.

2.3.2 Management of System Emergencies.

2.3.2.1 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.

2.3.2.2 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.

2.3.2.3 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.

2.3.2.3.1 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.

2.3.2.3.2 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.

2.3.2.3.3 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 DP 8.5 of the Dispatch Protocol.

2.3.2.3.4 The intervention will cease as soon as the ISO has restored all Demand that was curtailed on an involuntary basis under Section 2.3.2.3.2(d).

2.3.2.4 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 Section 2.3.2.7 below.

2.3.2.5 Periodic Tests of Emergency Procedures. The ISO shall develop and administer periodic unannounced tests of System Emergency procedures set out in the ISO Protocols. 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.

2.3.2.6 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 2.1.3, 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 4.5.3.2, 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 4.5.3.3, the prioritization schedule will include all UDCs and MSS Operators.

2.3.2.7 Further Obligations Relating to System Emergencies. The ISO and Participating TOs shall comply with their obligations in Section 9 of the TCA. The ISO and UDCs shall comply with their obligations in Section 4 of this ISO Tariff. The ISO and Generators shall comply with their obligations in Section 5 of this ISO Tariff.

2.3.2.8 Use of Load Curtailment Programs.

2.3.2.8.1 Use of UDC's Existing Load Curtailment Programs. As an additional resource for managing System Emergencies, the ISO will, subject to Section 2.1.3, notify the UDCs when the conditions to implement their Load curtailment programs have been met in accordance with their terms. 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.

2.3.2.8.2 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 Curtailable Demand as an Ancillary Service.

2.3.2.9 System Emergency Reports and Sanctions.

2.3.2.9.1 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.

2.3.2.9.2 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 2.3.2.9.1 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.

2.3.2.9.3 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 Paget details of all instances in which a sanction has been imposed.

2.3.3 Coordination of Outages and Maintenance.

2.3.3.1 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.

2.3.3.1.1 California Department of Water Resources. The provisions of Section 2.3.3, and the provisions of the Outage Coordination Protocol, shall apply to the California Department of Water Resources, except that Outages of hydroelectric Generating Units owned and operated by the California Department of Water Resources shall not be subject to approval or change by the ISO.

2.3.3.2 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.

2.3.3.3 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 2.3.3; and (ii) the requested Outage will not compromise ISO Controlled Grid reliability.

2.3.3.4 Single Point of Contact. Requests for approvals and coordination of all Maintenance Outages (consistent with Section 2.3.3.1) will be through a single point of contact between the ISO Outage Coordination Office and each Operator. The single point of contact for the ISO and each Operator will be specified from time to time by the Operator and the ISO pursuant to the detailed procedures referred to in Section 2.3.3.5.

2.3.3.5 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. In the case of a Participating TO's transmission facilties, 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 and set out in an ISO Protocol. Either the ISO, pursuant to Section 2.3.3.6, or an Operator, subject to Section 2.3.3.5.4, 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 2.3.3.5.1, 2.3.3.5.2, and 2.3.3.5.3.

2.3.3.5.1 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.

2.3.3.5.2 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.

2.3.3.5.3 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. 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.

2.3.3.5.4 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.

2.3.3.6 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 of 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 2.3.3.6.1 and 2.3.3.6.2 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 2.3.3.3, 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.

2.3.3.6.1 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.

2.3.3.6.2 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.

2.3.3.6.3 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 2.3.3.6. 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.

2.3.3.6.4 The amount used to compensate each applicable Participating TO and Participating Generator, as described in Section 2.3.3.6.3, 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.

2.3.3.7 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.

2.3.3.8 Final Approval. 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.

2.3.3.9 Forced Outages.

2.3.3.9.1 Coordination of all Forced Outages (consistent with Section 2.3.3.4) will be through the single point of contact between the Operator and the ISO Control Center.

2.3.3.9.2 All 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. If prior notice of a Forced Outage cannot be given, the Operator shall notify the ISO of the Forced Outage immediately after it occurs.

2.3.3.9.3 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.

2.3.3.9.4 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.

2.3.3.9.5 Within forty-eight (48) hours of the commencement of a Forced Outage, the Operator shall provide to the ISO an explanation of the Forced Outage, including 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 explanation 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 to determine if 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 forty-eight (48) hours or failed to provide any additional information or access to the generating facility requested by the ISO within a reasonable time.

2.3.3.10 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.

2.3.3.11 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.

2.3.4 Management of Overgeneration Conditions.

The ISO's management of Overgeneration relates only to real time. 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.

2.3.4.1 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.

2.3.4.2 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.

2.3.4.3 In addition to the action taken under 2.3.4.2, 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.

2.3.4.4 To the extent that the steps described in Sections 2.3.4.1 through 2.3.4.3 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.

2.3.4.5 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.

2.3.4.6 Any costs incurred by the ISO in implementing Section 2.3.4.3 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.

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

2.3.5.1 Generation Planning Reserve Criteria. Generation planning reserve criteria shall be met as follows:

2.3.5.1.1 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.

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

2.3.5.1.3 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 2.3.1.3.2). 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.

2.3.5.1.4 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.

2.3.5.1.5 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.

2.3.5.1.6 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.

2.3.5.1.7 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.

2.3.5.1.8 Except where and to the extent that such costs are recovered from Scheduling Coordinators pursuant to Section 2.5, and except as provided in Section 2.3.5.1.9, all costs incurred by the ISO in any hour pursuant to any contract entered into under this Section 2.3.5.1 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.

2.3.5.1.9 Costs incurred by the ISO pursuant to any contract entered into under this Section 2.3.5.1 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 2.5.28.4 bears to the total deviation Replacement Reserve in that hour.

2.4 [Not Used]

2.4.1 [Not Used]

2.4.1.1 [Not Used]

2.4.2 [Not Used]

2.4.2.1 [Not Used]

2.4.2.2 [Not Used]

2.4.3 Existing Contracts for Transmission Service.

2.4.3.1 In accordance with Section 2.4.4 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 2.4.4 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.

2.4.3.2 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 2.4.3 and Section 2.4.4.

2.4.3.3 The ISO will, if requested, advise parties to Existing Contracts regarding the operational aspects of any Existing Contract renegotiations that they undertake.

2.4.4 ISO Administration of Existing Contracts for Transmission Service.

2.4.4.1 Continuation of Rights and Obligations of Non-Participating TOs Under Existing Contracts.

2.4.4.1.1 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 2.4.4, the transmission service rights of Non-Participating TOs are called “Existing Rights.”

2.4.4.1.2 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 2.4.4.3.

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 7.1 of this Tariff.

2.4.4.1.3 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.

2.4.4.1.4 If the parties to an Existing Contract are unable to reach agreement on the changes needed to meet the requirements of Section 2.4.4.1.2 or Section 2.4.4.1.3, 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.

2.4.4.2 Conversion of Participating TOs' Rights and Obligations Under Existing Contracts.

2.4.4.2.1 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 2.4.4.3. 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 2.4.3 and 2.4.4, 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 2.4.4.3 with effect from the ISO Operations Date. Schedules that utilitze Converted Rights shall be submitted by a Scheduling Coordinator that has been certified in acccordance with Section 2.2.4.

2.4.4.2.2 As part of the conversion referred to in Section 2.4.4.2.1, 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 2.4.4.2.1 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.

2.4.4.3 Converted Rights.

2.4.4.3.1 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:

2.4.4.3.1.1 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;

2.4.4.3.1.2 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.

2.4.4.3.1.3 **[Not Used]**

2.4.4.3.1.4 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.

2.4.4.3.1.5 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.

2.4.4.3.2 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.

2.4.4.4 ISO Treatment of Non-Participating TOs Existing Rights.

2.4.4.4.1 For the purposes of Section 2.4.4, 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 Section 2.4.4.5.1.1. 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.

2.4.4.4.1.1 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.

2.4.4.4.2 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.

2.4.4.4.3 Scheduling deadlines and operational procedures associated with Existing Rights will be honored by the ISO.

2.4.4.4.4 All contractual provisions that have been communicated to the ISO in writing in accordance with Section 2.4.4.4.1 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.

2.4.4.4.4.1 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.

2.4.4.4.4.2 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.

2.4.4.4.4.3 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.

2.4.4.4.4.4 [Not Used]

2.4.4.4.4.5 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.

2.4.4.5 ISO Protocols Shall Accommodate Existing Rights.

The ISO will implement the provisions of Section 2.4.4.4 in its Scheduling Protocol. The objective will be to ensure that under the ISO rules and protocols, 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 Scheduling Protocol:

2.4.4.5.1.1 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 2.4.4.4.1.1.

2.4.4.5.1.2 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 2.4.4.4.1.1.

2.4.4.5.1.3 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. In this case, the ISO shall act as the scheduling agent for the Participating TOs with regard to Existing Rights.

2.4.4.5.1.4 The ISO shall determine, based on the information provided by the Participating TOs and contract rights holders under Sections 2.4.4.5.1.2 and 2.4.4.5.1.3, 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.

2.4.4.5.1.5 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.

2.4.4.5.1.6 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.

2.4.4.5.2 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).

2.4.4.5.3 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 2.4.4.

2.4.4.5.4 Unless specified otherwise, in the event that the dispute resolution mechanisms prescribed in an Existing Contract, including all recourses legally available under the contract, 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 2.4.3 and 2.4.4, 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.

2.5 Ancillary Services.

2.5.1 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. 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.

2.5.2 Ancillary Services Standards.

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

2.5.2.1 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) 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 national 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.

2.5.2.2 Time-frame For Revising Ancillary Service Standards. 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 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.

2.5.3 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:

2.5.3.1 Regulation Service. The ISO shall maintain sufficient Generating Units immediately responsive to AGC in order to provide sufficient Regulation service to allow the system to meet WECC and NERC criteria.

2.5.3.2 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 to be met by Generation from hydroelectric resources plus 7% of the Demand 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. 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 Interruptible Imports scheduled by Scheduling Coordinators for any hour. 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.

2.5.3.3 Replacement Reserve. 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.

2.5.3.4 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, 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. 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 2.5.18.

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.

2.5.3.5 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.

2.5.3.6 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;

(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 2.5.3.6; and

(h) All quantities of Ancillary Services so procured must be non-negative.

2.5.4 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.

2.5.4.1 Black Start Units.

(a) must be located in the ISO Control Area;

(b) may be located anywhere in the ISO Controlled 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.

2.5.5 Time-frame For Contracting for Ancillary Services.

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 2.3.5.1.3 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.

2.5.6 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 2.5.6.1 to 2.5.6.4 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 arenot being met, the ISO may withdraw the certificate for the Generating Unit, System Unit, Load or System Resource concerned.

2.5.6.1 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 2.5.3.4;

(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.

2.5.6.2 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. 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.

2.5.6.3 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.

2.5.6.4 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.

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

2.5.7.1 [NOT USED]

2.5.7.2 Usage Charge in Ancillary Service Bid Evaluation.

As of the ISO Operations Date, the ISO will not incorporate forecast Usage Charges into its Ancillary Service bid evaluations as the means to evaluate Ancillary Service bids across Zones when Congestion is present.

2.5.7.3 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.

2.5.7.4 Bidding and Self-Provision of Ancillary Services

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

2.5.7.4.1 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.

2.5.7.4.2 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).

2.5.7.4.3 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; 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 in accordance with ISO standards and procedures posted on the ISO Home Page.

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

2.5.7.4.5 Scheduling Coordinators' bidding or self-provision of Ancillary Services according to this Section 2.5.7.4 shall be consistent with the ISO Protocols.

2.5.8 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.

2.5.9 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 2.2.10. 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.

2.5.10 Time Frame for Submitting And Evaluating Bids.

2.5.10.1 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.

2.5.10.2 Hour-Ahead Auction. 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 2.5.21 must do so by submitting a revised bid in the Hour-Ahead Market for the Ancillary Service and resource concerned.

2.5.11 Information To Be Submitted By Bidders.

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 2.5.14 to 2.5.19 and such other information as the ISO may determine it requires to evaluate bids as published from time to time in 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).

2.5.12 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.

2.5.13 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 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.

2.5.14 The Regulation Auction.

Bid Information. Each Scheduling Coordinator j shall 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) $Ramp_{ijt}$;

(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; and

(h) the bid price of the capacity reservation, stated separately for Regulation Up and Regulation Down ($CapRes_{ijt}$ ($/MW)).

(i) the bid price of the Energy output from the reserved capacity ($EnBid_{ijt}$($/MWh));

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

(a) bidder name/Identification Code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) Scheduling Point;

(d) interchange ID code;

(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));

(n) the bid price of the Energy output from the reserved capacity ($EnBid_{ijt}$($/MWh)).

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 $Period_{minutes.}$

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:

$$Min \sum_{i,j} TotalBid_{ijt}$$

Subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t \text{ and } Cap_{ijt} \leq Cap_{ijtmax}$$

Where

$TotalBid_{ijt} = CapRes_{ijt} * Cap_{ijt}$

$Requirement_t$ = 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:

$PAGC_x = MCP_{xt}$

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.

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

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 2.5.21 shall be the bid price of the Regulation Capacity reserved ($CapRes_{ijt}$ *($/MW))*.

2.5.15 The Spinning Reserve Auction.

<u>Bid Information</u>. 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 ($Cap_{ijt}max$) 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));and

(i) bid price of Energy output from reserved capacity ($EnBid_{ijt}$ ($/MWh)); and

(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.

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 ($Cap_{ijt}max$) 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) bid price of Energy output from reserved capacity ($EnBid_{ijt}$ ($/MWh));

(g) 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:

(h) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(i) Scheduling Point;

(j) interchange ID code;

(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; and

(n) the contract reference number, if applicable.

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:

$$Min\sum_{i,j} Totalbid_{ijt}$$

Subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

and $Cap_{ijt} \leq Cap_{ijt}max$

Where

$TotalBid_{ijt} = Cap_{ijt} * CapRes_{ijt}$

$Requirement_t$ = the amount of Spinning Reserve capacity required

<u>Price Determination</u>. 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:

$Psp_{xt} = MCP_{xt}$

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.:

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

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 2.5.21 shall be the bid price of the Spinning Reserve capacity reserved ($CapRes_{ijt}$($/MW)).

2.5.16 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 ($Cap_{ijt}max$);

(h) the bid price of the capacity reserved ($CapRes_{ijt}$($/MW));

(i) time to synchronization following notification (min);

(j) the bid price of the Energy output from the reserved capacity ($EnBid_{ijt}$($/MWh)); and

(k) 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.

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 ($Cap_{ijt}max$) 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) the bid price of Energy output from reserved capacity ($EnBid_{ijt}$($/MWh));

(g) 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:

(h) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(i) Scheduling Point;

(j) interchange ID code;

(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; and

(n) the contract reference number, if applicable.

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)); and

(h) the bid price for Demand reduction from the reserved capacity ($EnBid_{ijt}$($/MWh)); and

(i) 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

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:

$$Min \sum_{i,j} Totalbid_{ijt}$$

Subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

$$Cap_{ijt} \leq Cap_{ijt}max$$

Where

$TotalBid_{ijt} = Cap_{ijt} * CapRes_{ijt}$

$Requirement_t$ = 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:

$Pnonsp_{xt} = MCP_{xt}$

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.:

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

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 2.5.21 shall be the bid price of the Non-Spinning Capacity reserved ($CapRes_{ijt}(\$/MW)$).

2.5.17 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 ($Cap_{ijt}max$);

(h) the bid price of the capacity reserved ($CapRes_{ijt}$ *($/MW))*; and

(i) time to synchronize following notification (min); and

(j) the bid price of the Energy output from the reserved capacity ($EnBid_{ijt}$ ($/MWh)).

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 ($Cap_{ijt}max$) 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) bid price of Energy output from reserved capacity ($EnBid_{ijt}$ ($/MWh)); 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;

(i) interchange ID code;

(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; and

(m) the contract reference number, if applicable.

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); and

(g) the bid price of the capacity reserved ($CapRes_{ijt}$ ($/MW));

(h) the bid price of the Demand reduction from the reserved capacity ($EnBid_{ijt}$ ($/MWh)).

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:

$$Min \sum_{i,j} Totalbid_{ijt}$$

Subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

$$Cap_{ijt} \leq Cap_{ijt} max$$

Where

$TotalBid_{ijt} = Cap_{ijt} * CapRes_{ijt}$

$Requirement_t$ = the amount of Replacement Reserve capacity

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, be the Zonal Market Clearing Price for Replacement Reserve calculated as follows:

$PRepRes_{xt} = MCP_{xt}$

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.:

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

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 2.5.21 shall be the bid price of the Replacement Reserve capacity reserved ($CapRes_{ijt}$(*$/MW*)).

2.5.18 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 2.5.3.4.

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:

Max{0, Zonal BEEP Interval Ex Post Price - Generating Unit bid price } x 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.

2.5.19 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.

2.5.20 Obligations for and Self-Provision of Ancillary Services.

2.5.20.1 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 2.5.20 and in Section 2.5.28 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 2.5.28.4. 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 2.5.3.6.

2.5.20.2 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 2.5.14 to 2.5.17. In accordance with Section 2.5.22.11 and Section 2.5.26.2, 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 2.5.26.2 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 2.5.20.5.2. 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 2.5.21.

2.5.20.3 [Not Used]

2.5.20.4 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.

2.5.20.5 Time Frame for Informing ISO of Self-Provision.

2.5.20.5.1 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 2.5.10.1. 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.

2.5.20.5.2 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 2.5.10.2. 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.

2.5.20.6 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 2.5.14 to 2.5.17, excluding the capacity price information, but including the name of the trading Scheduling Coordinator in the case of Inter-Scheduling Coordinator Ancillary Service Trades.

2.5.20.7 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.

2.5.21 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. The ISO Protocols set forth the information, which will be included in these schedules. 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 5.11, as the ISO's auction does not compensate the Scheduling Coordinator for the minimum energy output of Generating Units bidding to provide these services. Accordingly, except as set forth under Section 5.11, the Scheduling Coordinators shall adjust their schedules to accommodate the minimum outputs required by the Generating Units 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.

2.5.22 Rules For Real-Time Dispatch of Imbalance Energy Resources.

2.5.22.1 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.

2.5.22.2 General Principles. The ISO shall base real-time Dispatch of Generating Units, System Units, Loads and System Resources on the following principles:

(a) the ISO shall dispatch Generating Units, System Units, and System Resources providing Regulation service to meet NERC and WECC Area Control Error (ACE) performance requirements;

(b) once ACE has returned to zero, the ISO shall determine whether the Regulation Generating Units, System Units, and System Resources are operating at a point away from their preferred operating point. The ISO shall then adjust the output of Generating Units, System Units, and System Resources available (either providing Spinning Reserve, Non-Spinning Reserve, Replacement Reserve or offering Supplemental Energy) to return the Regulation Generating Units, System Units, and System Resources to their preferred operating points to restore their full regulating margin;

(c) the ISO shall dispatch Generating Units, System Units, Loads and System Resources only to meet its Imbalance Energy requirements. The ISO shall not dispatch such resources in real time for economic trades either between Scheduling Coordinators or within a Scheduling Coordinator portfolio;

(d) subject to Section 2.5.22.3 and its subparts, the ISO shall select the Generating Units, System Units, Loads and System Resources to be dispatched to meet its Imbalance Energy requirements based on a merit order of Energy bid prices;

(e) subject to Section 2.5.22.3 and its subparts, the ISO shall not discriminate between Generating Units, System Units, Loads 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;

price, and the effectiveness (e.g., location and ramp rate) of the resource concerned to respond to the fluctuation in Demand or Generation;

(f) Generating Units, System Units, Loads 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 BEEP Interval.

2.5.22.3 Ancillary Services Dispatch. 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.

2.5.22.3.1 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 bid prices as described in their Ancillary Service schedule and their effectiveness, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 2.5.22.3.

2.5.22.3.2 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 position of the Generating Unit, Load, System Unit or System Resource in the merit order for real time Dispatch, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 2.5.22.3.

2.5.22.4 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.

2.5.22.4.1 Timing of Supplemental Energy Bids.

Supplemental Energy bids must be submitted to the ISO no later than sixty (60) 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 (60) minutes prior to the Settlement Period, except that a bid from a System Resource may specify that any portion of the bid that is not called prior to the beginning of the Settlement Period shall not be called after the beginning of the Settlement Period. The ISO may dispatch the associated resource at any time during the Settlement Period..

2.5.22.4.2 Form of Supplemental Energy Bid Information.

Supplemental Energy bids must include the information specified in Schedules and Bids Protocol Section 6.1 following:

(a) Bidder name and identification;

(b) Resource name, identification, and location;

(c) the positive or negative bid price of incremental and decremental changes in Energy (up to eleven ordered pairs of quantity/price representing up to ten steps);.

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

(e) Generating Unit ramp rate (MW/Min); and

(f) Such other information as the ISO may determine it requires to evaluate bids, as published from time to time in ISO Protocols.

2.5.22.5 Information used in the Real Time Dispatch. The ISO shall place all the bid price information (except for Regulation bid prices and Adjustment Bids carried forward from the Day-Ahead and Hour-Ahead Markets) received from available Generating Units, Loads, System Units and System Resources in a database for use in real time Dispatch of Balancing Energy. The database shall indicate:

(a) Generating Unit/Load/ System Unit/ System Resource name;

(b) congestion zone;

(c) quantity bid;

(d) normal ramp rate;

(e) price;

(f) whether the Generating Unit/ Load/ System Unit/ System Resource has been contracted to provide any Ancillary Services and/or Supplemental Energy, and, if so, which ones.

The quantity blocks shall be ordered in a merit order stack of ascending incremental and descending decremental price bids. Energy bids associated with Spinning and Non-Spinning Reserve shall be included in the merit order stack during normal operating conditions unless 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.

2.5.22.6 **Real-Time Dispatch.** The ISO shall select the least cost Generating Unit, Curtailable Demand, System Unit or System Resource that is effective to meet Imbalance Energy requirements, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 2.5.22.3. The ISO shall determine that additional output is needed if the current output levels of the Regulation Generating Units, System Units, and System Resources exceed their preferred operating points by more than a specified threshold (to be determined by the ISO). The ISO shall determine that less output is needed if the output levels of the Regulation Generating Units, System Units, and System Resources fall below their preferred operating points by more than a specified threshold (to be determined by the ISO). To minimize the cost of providing Imbalance Energy:

(a) if additional Energy output, or Demand reduction, is needed, the ISO shall Dispatch additional output or reduce Demand from Generating Units, Loads, System Units or System Resources in ascending order of their incremental Supplemental Energy Bid prices (or, for Generating Units, Loads, System Units and System Resources providing Ancillary Services, their Energy Bid prices).

(b) if the ISO is required to reduce Energy output from Generating Units, Loads, System Units or System Resources, the ISO shall dispatch down Generating Units, Loads, System Units and System Resources in descending order of their decremental Supplemental Energy bid prices (or, for Generating Units, Load, System Units and System Resources providing Ancillary Services their Energy Bid prices).

Once a bid has been accepted by the ISO, the database shall be adjusted to reflect the change in status of the bid. Once a decremental bid has been used by the ISO, it will then be included in the incremental part of the database with an incremental bid equal to its decremental price bid. Once an incremental bid has been used by the ISO it will then be included in the decremental part of the database with a decremental bid equal to its incremental price bid. In the event that the ISO subsequently needs to decrement output, it will initially decrement the Generating Units, Loads, System Units or System Resources incremented previously, and then continue down the merit order of the decremental bids.

2.5.22.7 Inter-Zonal Congestion. In the event of Inter-Zonal Congestion in real time, the ISO shall procure Imbalance Energy separately for each Zone, as described in Section 2.5.22.6.

2.5.22.8 Intra-Zonal Congestion. Except as provided in Section 5.2, in the event of Intra-Zonal Congestion in real time, the ISO shall adjust resources in accordance with Sections 7.2.6.1 and 7.2.6.2.

2.5.22.9 Replacement of Operating Reserve. If pre-arranged Operating Reserve is used to meet Imbalance Energy requirements, such Operating Reserve may be replaced by the ISO's dispatch of Energy through available Supplemental Energy Bids.

Any additional Operating Reserve needs may also be met in the same way. through unloaded capacity from RMR resources. Where the ISO elects to rely upon Supplemental Energy Bids, the ISO shall select the resources with the lowest incremental Energy price bids. Operating Reserve procured from Replacement Reserve shall not require replacement of utilized Replacement Reserve.

2.5.22.10 Dispatch Instructions.

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. 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 recipient of a Dispatch instruction shall confirm the Dispatch. 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.

The ISO Protocols govern the content, issue, receipt, confirmation and recording of Dispatch instructions.

2.5.22.11 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. 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;

(b) cannot set the Beep Interval Ex Post Price; and the Scheduling Coordinator for the Participating Generator, owner or operator of the Curtailable Demand or System Resource concerned shall pay to the ISO the difference between the Generating Unit's, Curtailable Demand's or System Resource's instructed and actual output (or Demand) at the Beep Interval Ex Post Price in accordance with Section 11.2.4.1. This applies whether the Ancillary Services concerned are contracted or self-provided.

The ISO will develop additional mechanisms to deter Generating Units, Curtailable Demand and System Resources from failing to perform according to Dispatch instructions, for example 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.

2.5.23 Pricing Imbalance Energy.

2.5.23.1 General Principles. Instructed and Uninstructed Imbalance Energy shall be priced using the BEEP Interval Ex Post Prices. The BEEP Interval Ex Post Prices shall be based on the bid of the marginal Generating Units, System Units, and Loads dispatched by the ISO to increase or reduce Demand or Energy output in each BEEP Interval as provided in Section 2.5.23.2.1.

The marginal Generating Unit, System Unit, Load or System Resource provides

(a) Incremental Energy if Generation output is increased, or Demand reduced, or

(b) Decremental Energy if Generation output is decreased, or Demand increased.

For Incremental Energy, the marginal bid is the Generating Unit, System Unit, Load or

System Resource with the highest bid that is accepted by the ISO's BEEP Software for increased Generation, or reduced Demand. For Decremental Energy, the marginal bid is the Generating Unit, System Unit, Load or System Resource with the lowest bid that is accepted by the ISO's BEEP Software for reduced Generation or increased Demand.

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 BEEP 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 BEEP Software.

2.5.23.2 Determining Ex Post Prices.

2.5.23.2.1 BEEP Interval Ex Post Prices. For each BEEP Interval, the ISO will compute an updated supply curve, using the Generating Units, System Units, and Loads dispatched according to the ISO's BEEP Software during that time period to meet Imbalance Energy requirements. The BEEP 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 2.5.23.3. . For each BEEP Interval of the Settlement Period, BEEP will compute an incremental Ex Post Price and a decremental Ex Post Price. The BEEP Interval Ex Post Price for incremental Energy will be the highest incremental marginal bid selected by the BEEP software in the corresponding BEEP Interval. The BEEP Interval Ex Post Price for decremental Energy will be the lowest price decremental marginal bid selected by the BEEP software in the corresponding BEEP Interval. If only decremental Imbalance Energy is dispatched in a BEEP Interval, then the BEEP Interval Ex Post Price for incremental Energy will be equal to the BEEP Interval Ex Post Price for decremental Energy. If only incremental Imbalance Energy is dispatched in a BEEP Interval, then the BEEP Interval Ex Post Price for decremental Energy will be equal to the BEEP Interval Ex Post Price for incremental Energy.

In the event of Inter-Zonal Congestion, the ISO will develop a dispatch price curve, and the BEEP Interval Ex Post Prices for each Zone where congestion exists.

2.5.23.2.2 Hourly Ex Post Price Applicable to Uninstructed Deviations. The Hourly Ex Post Price in Settlement Period t in each zone will equal the Energy weighted average of the BEEP Interval Charges in each Zone, calculated as follows:

$$PHourExPostx = \frac{(\sum_{ji} \left|MWh_{jix}\right| * BIP_{ix})}{\sum_{ji} \left|MWh_{jix}\right|}$$

Where:

$PHourExPost_x$ = Hourly Ex Post Price in Zone x

BIP_{ix}= BEEP Interval Ex Post Price

J=the number of Scheduling Coordinators with instructed deviations

MWH_{jix}=the Instructed Imbalance Energy for Scheduling Coordinator j for the BEEP Interval i in Zone x.

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.

2.5.23.3 **[Not Used]**

2.5.23.3.1 **[Not Used]**

2.5.23.3.1.1 **[Not Used]**

2.5.23.3.1.2 [Not Used]

2.5.23.3.1.3 [Not Used]

2.5.23.3.2 [Not Used]

2.5.23.3.3 Requirement of Must-Offer Generators to File Heat Rate and Emissions Rate Data

Must-Offer Generators, as defined in Section 5.11 of this ISO Tariff, that own or control gas-fired Generating 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 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 Home Page. Heat rate data provided to comply with this requirement shall not include start-up or minimum load fuel costs. 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 2.5.23.3.3 as confidential and will apply the procedures in Section 20.3.4 of this ISO Tariff with regard to requests for disclosure of such information. **2.5.23.3.4 Calculation of the Proxy Price**

The ISO shall calculate each day separate Proxy Prices for each gas-fired Generating Unit owned or controlled by a Must-Offer Generator by applying the filed heat rates for those Generating Units to a daily proxy figure for natural gas costs with an additional $6/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 Home Page by 8:00 AM on the day prior to which the figures will be used for calculation of the Proxy Price.

2.5.23.3.5 [Not Used]

[Page Not Used]

2.5.23.3.6 Emissions Costs

2.5.23.3.6.1 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 Must-Offer Generator as a direct result of an ISO Dispatch instruction, in accordance with this Section 2.5.23.3.6. The ISO shall levy this administrative charge (the “Emissions Cost Charge”) each month, against all Scheduling Coordinators based upon each Scheduling Coordinator’s Control Area Gross Load and Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area. Scheduling Coordinators shall make payment for all Emissions Cost Charges in accordance with the ISO Payments Calendar.

2.5.23.3.6.2 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.

2.5.23.3.6.3 Rate For the Emissions Cost Charge

The rate at which the ISO will assess the Emissions Cost Charge shall be at the projected annual total of all Emissions Costs incurred by Must-Offer Generators as a direct result of ISO

Dispatch instruction, adjusted for interest projected to be earned on the monies in the Emissions Cost Trust Account, divided by the sum of the Control Area Gross Load and the projected Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area of all Scheduling Coordinators for the applicable year ("Emissions Cost Demand"). The initial rate for the Emissions Cost Charge, and all subsequent rates for the Emissions Cost Charge, shall be posted on the ISO Home Page.

2.5.23.3.6.4 Adjustment of the Rate For the Emissions Cost Charge

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

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

(b) the difference, if any, between the projections of the Emissions Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instructions and the actual Emissions Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instructions as invoiced to the ISO and verified in accordance with this Section 2.5.23.3.6; and

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

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

2.5.23.3.6.5 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.

2.5.23.3.6.6 Submission of Emissions Cost Invoices

Scheduling Coordinators for 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 Home Page (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 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, 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.

2.5.23.3.6.7 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 2.5.23.3.6.4. 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.

2.5.23.3.7 Start-Up Costs

2.5.23.3.7.1 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 Must-Offer Generator as a direct result of an ISO Dispatch instruction, in accordance with this Section 2.5.23.3.7. Such Start-Up Costs shall include (1) fuel and (2) auxiliary power. The ISO shall levy this charge (the "Start-Up Cost Charge"), each month, against all Scheduling Coordinators based upon each Scheduling Coordinator's Control Area Gross Load and Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area. Scheduling Coordinators shall make payment for all Start-Up Cost Charges in accordance with the ISO Payments Calendar.

2.5.23.3.7.2 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.

2.5.23.3.7.3 Rate For the Start-Up Cost Charge

The rate at which the ISO will assess the Start-Up Cost Charge shall be at the projected annual total of all Start-Up Costs incurred by Must-Offer Generators as a direct result of

ISO Dispatch instruction, adjusted for interest projected to be earned on the monies in the Start-Up Cost Trust Account, divided by the sum of the Control Area Gross Load and the projected Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area ("Start-Up Cost Demand"). The initial rate for the Start-Up Cost Charge, and all subsequent rates for the Start-Up Cost Charge, shall be posted on the ISO Home Page**.**

2.5.23.3.7.4 Adjustment of the Rate For the Start-Up Cost Charge

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

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

(b) the difference, if any, between the projections of the Start-Up Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instructions and the actual Start-Up Costs incurred by Must-Offer Generators as a direct result of ISO Dispatch instructions as invoiced to the ISO and verified in accordance with this Section 2.5.23.3.7; and

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

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

2.5.23.3.7.5 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.

2.5.23.3.7.6 Submission of Start-Up Cost Invoices

Scheduling Coordinators for 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 must-offer obligation while the unit is off-line in accordance with Section 5.11.6 of this ISO Tariff, and Scheduling Coordinators for Generating 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 Home Page (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 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 Must-Offer Generator.

2.5.23.3.7.7 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 2.5.23.3.7.4. 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.

2.5.23.3.8 [Not Used]

2.5.23.3.8.1 Hydro-Electric Resources within the ISO Control Area.

Hydro-electric resources within the ISO Control Area are not required to submit $0/MWh or other price-taker bids and are eligible to set a market clearing price.

2.5.23.3.8.2 [Not Used]

2.5.24 Verification of Performance 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. Participating Generators, owners or operators of Loads, operators of System Units or System Resources 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 and operators of System Units or System Resources 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.

2.5.25 Periodic Testing of Units.

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.

2.5.25.1 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.

2.5.25.2 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. 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.

2.5.25.3 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.

2.5.25.4 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.

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

2.5.25.6 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 2.5.27.6 for the Generating Unit shall be paid the Generating Unit's contract price for the output under the Black Start test.

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

2.5.26.1 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 2.5.26.2 or 2.5.26.3.

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 2.5.26, 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.

2.5.26.2 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 BEEP 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.

2.5.26.2.1 If the ISO determines that a Scheduling Coordinator has supplied Uninstructed Imbalance Energy to the ISO during a BEEP 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 BEEP 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 and for Energy supplied from such capacity 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 BEEP 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 2.5.26.1 with respect to the deficiency.

2.5.26.2.2 If the metered Demand of 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 BEEP Interval, then the related capacity payments will be rescinded to the extent of that deficiency as explained in Section 2.5.26.2.4 and 2.5.26.2.5, unless a penalty is imposed on that Curtailable Demand for that BEEP Interval under Section 2.5.26.1.

2.5.26.2.3 The payment for Energy to be eliminated shall be determined in accordance with Section 11.2.4.1.

2.5.26.2.4 This Section 2.5.26.2.4 shall not apply to the capacity payment for any particular Ancillary Service if the Zonal Market Clearing Price determined in accordance with Sections 2.5.15, 2.5.16 or 2.5.17 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 2.5.27.2, 2.5.27.3, and/or 2.5.27.4 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 BEEP 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. The amount of capacity for which payments will be rescinded shall equal the value $UnavailAncServMW_{ixt}$, as defined in Section 11.2.4.1, applied to each Generating Unit, System Unit and System Resource supplying the Ancillary Service or the value $UnavailDispLoadMW_{ixt}$, as also defined in Section 11.2.4.1, applied to the Curtailable Demand supplying the Ancillary Service.

2.5.26.2.5 Payment shall be eliminated first for any Spinning 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 Spinning Reserve capacity for which it would otherwise be entitled to receive payment, payment shall be eliminated for Non-Spinning

Reserve capacity, and then for Replacement 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.

2.5.26.2.6 For each BEEP Interval in which a Generating Unit, Curtailable Demand, System Unit or System Resource fails to 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 BEEP 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 BEEP Interval.

2.5.26.3 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 deliver 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 BEEP 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 BEEP Interval. For any BEEP 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.

2.5.26.4 Penalties applied pursuant to Section 2.5.26.1, and payments rescinded pursuant to Section 2.5.26.2 and 2.5.26.3 shall be redistributed to Scheduling Coordinators in proportion to ISO Control Area metered Demand and scheduled exports for the same Trading Day.

2.5.26.5 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.

2.5.26.6 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 2.5.26.2.3 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.

2.5.27 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.

2.5.27.1 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:

$AGCUpQDA_{xt}$ = 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.

$AGCDownQDA_{xt}$ = 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.

$EnQUnst_{xt}$ = Uninstructed Imbalance Energy increase or decrease in Zone X in real-time Dispatch for each BEEP 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 2.5.14.

Adjustment: penalty described in Section 2.5.26.1.

$PAGCUpDA_{xt}$ = 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 payment for Energy output from Regulation in accordance with settlement for Uninstructed Imbalance Energy under Section 11.2.4.1.

$$\sum_i \mathbf{[}(EnQUnst_{ixt} * HourlyExPostPriceinZoneX) + REPA_{ixt}\mathbf{]}$$

$REPA_{ixt}$ = the Regulation Energy Payment Adjustment for Generating Unit i in Zone X for 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} = 1

C_{DN} = 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.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.

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.

2.5.27.2 Spinning Reserve.

<u>Quantities</u>. 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.

<u>Prices</u>. The prices in the Settlement process for Spinning Reserve shall be those determined in Section 2.5.15.

Adjustment = penalty described in Section 2.5.26.1, or rescinded capacity payments described in Section 2.5.26.2 or 2.5.26.3.

$PspDA_{xt}$ = 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:

$EnQInst_{xt}$ * *BEEP Interval Ex Post Price*$_{xt}$

2.5.27.3 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 2.5.16.

Adjustment = penalty described in Section 2.5.26.1, or rescinded capacity payments described in Section 2.5.26.2 or 2.5.26.3.

$PnonspDA_{xt}$ = 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:

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

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

$EnQInst_{xt} * BEEP\ Interval\ Ex\ Post\ Price_{xt}$

2.5.27.4 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 2.5.17.

Adjustment = penalty described in Section 2.5.26.1, or rescinded capacity payments described in Section 2.5.26.2 or 2.5.26.3.

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

<u>Payments</u>. 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:

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

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:

$EnQInst_{ijt}\ *\ BEEP\ Interval\ Ex\ Post\ Price_{xt}$

2.5.27.5 <u>Voltage Support</u>. 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 2.5.18, and the payments under long-term contracts.

2.5.27.6 <u>Black Start</u>.

<u>Quantities</u>. 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.

<u>Prices</u>. The prices used in the Settlement process are those described in the contracts referred to in Section 2.5.19.

Adjustment = penalty described in Section 2.5.26.1.

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 BSSUPijt 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).

2.5.27.7 **[Not Used]**

2.5.27.7.1 **[Not Used]**

2.5.27.7.2 [Not Used]

2.5.27.7.3 [Not Used]

2.5.27.7.4 [Not Used]

2.5.28 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 2.5.20.1, notwithstanding any adjustment to the quantities of each Ancillary Service purchased by the ISO in accordance with Section 2.5.3.6.

The cost of Voltage Support and Black Start shall be allocated to Scheduling Coordinators as described in Sections 2.5.28.5 and 2.5.28.6.

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 2.5.28.1, 2.5.28.2, 2.5.28.3 and 2.5.28.4, 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 2.5.3.6, then in lieu of the user rate determined in accordance with Section 2.5.28.1, 2.5.28.2, 2.5.28.3, or 2.5.28.4, 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 2.5.28.1 through 2.5.28.4 or Section 2.5.28(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 2.5.27.1 through 2.5.27.4, for the Day-Ahead Market and Hour-Ahead Market and all Zones, exceed (ii) the total amounts charged to Scheduling Coordinators pursuant to Section 2.5.28.1 through 2.5.28.4, 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.

2.5.28.1 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.

2.5.28.2 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.

2.5.28.3 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.

2.5.28.4 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 2.5.3.6.

$OrigReplReqHA_{xt}$ = 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 2.5.3.6.

$PRepResDA_{xt}$ 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 Section 11.2.4.1.

$LoadDev_{ijxt}$ = 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 Section 11.2.4.1.

$DevReplOblig_{xt}$ 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.

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

2.5.28.5 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:

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

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.

2.5.28.6 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:

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

2.5.29 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

2.5.30 Communication Protocols.

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

2.5.30.1 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 2.2.7.6, 2.5.6.2 and 2.5.7.4.2.

2.5.30.2 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.

2.5.30.3 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 6.1 and 6.2. 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.

2.6 Incorporation of the ISO Market Monitoring & Information Protocol

The ISO shall monitor the markets that it administers in order to identify and, where appropriate, institute corrective action to respond to the exercise of market power or other abuses of such markets in accordance with the ISO Market Monitoring & Information Protocol set forth in Appendix L, “ISO Protocols.”

3. RELATIONSHIP BETWEEN ISO AND PARTICIPATING TOs.

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 2.4.4.2, 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.

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.

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 2.2.4, 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.

3.2 Transmission Expansion.

A Participating TO shall be obligated to construct all transmission additions and upgrades that are determined to be needed in accordance with the requirements of this Section 3.2 and which: (1) are additions or upgrades to transmission facilities that are located within its PTO Service Territory, unless it does not own the facility being upgraded or added and neither terminus of such facility is located within its PTO Service Territory; or (2) are additions to existing transmission facilities or upgrades to existing transmission facilities that it owns, that are part of the ISO 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 3.2.7. 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 the TO's obligations under this ISO Tariff or as those rights may be conferred by the ISO or may arise or exist pursuant to this ISO Tariff.

3.2.1 Determination of Need.

A Participating TO or any other Market Participant may propose a transmission system addition or upgrade. The ISO will determine that a transmission addition or upgrade is needed where it will promote economic efficiency or maintain System Reliability as set forth below.

3.2.1.1 Economically Driven Projects. The Participating TO and Market Participants shall provide the necessary assistance and information to the ISO, as part of the coordinated planning process, to enable the ISO to determine that a project is needed to promote economic efficiency, including, at the ISO's discretion, studies comporting with ISO guidelines that demonstrate whether the project will promote economic efficiency or the information the ISO requires to carry out its own studies for economically driven projects. The ISO shall treat market sensitive information provided to the ISO in accordance with this Section by Participating TOs, Project Sponsors and applicable Market Participants confidentially in accordance with Section 20.3 provided that such information is clearly marked "Confidential" at the time it is provided to the ISO. The determination that a transmission addition or upgrade is needed to promote economic efficiency shall be made in any of the following ways:

3.2.1.1.1 If the Participating TO or any party questions the economic need for the project (except where the Project Sponsor commits to pay the full cost of construction) the proposal will be submitted to the ISO ADR Procedures for resolution.

3.2.1.1.2 Where a Project Sponsor other than the Participating TO commits to pay the full cost of construction of a transmission addition or upgrade and its operation, and demonstrates to the ISO financial capability to pay those costs, such commitment and demonstration shall be sufficient to demonstrate need to the ISO. To ensure that the Project Sponsor is financially able to pay the costs of the project to be constructed by the Participating TO, 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.

3.2.1.1.3 Where a Project Sponsor asserts that a transmission addition or upgrade is economically beneficial, but that Project Sponsor is unwilling to commit to pay the full cost of the addition or upgrade; where (1) the proposed transmission addition or upgrade was submitted to the Participating TO but was not included in the transmission expansion plan of that Participating TO in accordance with Section 3.2.2 or (2) the operation date of the planned expansion is not acceptable to the ISO or the Project Sponsor or (3) the Participating TO unreasonably delays implementing or subsequently decides not to proceed with the project, the Project Sponsor may submit its proposal to the ISO ADR Procedure for determination of need. A determination of need shall be made as follows:

3.2.1.1.3.1 The Project Sponsor shall include in its proposal: (1) a showing that the economic benefits of the proposed transmission addition or upgrade are expected to exceed its costs (giving consideration to any reasonable alternatives to the construction of transmission additions or upgrades) using an economic analysis that comports with ISO guidelines, and (2) a statement of the proposed pricing methodology for the transmission upgrades or additions that the Project Sponsor elects in accordance with Section 3.2.7 of the ISO Tariff.

3.2.1.1.3.2 If neither any Market Participant nor the ISO disputes the Project Sponsor's showing, then the proposal is determined to be needed.

3.2.1.1.3.3 If any Market Participant or the ISO disputes the Project Sponsor's showing, the disputing Market Participant, the ISO, or the Project Sponsor may submit to resolution through the ISO ADR Procedure the issue of whether the transmission addition or upgrade is needed on the ground that its economic benefits exceed its costs. If a Market Participant fails to raise through the ISO ADR Procedure a dispute as to whether a proposed transmission addition or upgrade is needed, then the Market Participant shall be deemed to have waived its right to raise such dispute at a later date. The determination under the ISO ADR Procedure as to whether the transmission addition or upgrade is needed, including any determination by FERC or on appeal of a FERC determination in accordance with that process, shall be final.

3.2.1.2 Reliability Driven Projects. The ISO in coordination with the Participating TO, will identify the need for any transmission additions or upgrades required to ensure System Reliability consistent with all Applicable Reliability Criteria. In making this determination, the ISO, in coordination with the Participating TO 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 or reactive support. The Participating TO, in cooperation with the ISO, shall perform the necessary studies to determine the facilities needed to meet all Applicable Reliability Criteria. The Participating TO shall provide the ISO and other Market Participants with all information relating to a proposed transmission addition or upgrade that they may reasonably request (other than information available to them through the WECC or any other applicable regional organization) and shall, through the WECC or any other applicable regional organization coordinated planning processes, develop the scope of and assumptions for such studies that are acceptable to the ISO and those other Market Participants. The ISO shall be free to propose any transmission upgrades or additions it deems necessary to ensure System Reliability consistent with Applicable Reliability Criteria, and, subject to appropriate appeals, the Participating TO shall be obligated to construct such lines. After the ISO Operations Date, the ISO, in consultation with Participating TOs and any affected UDCs and MSSs, will work to develop a consistent set of Reliability Criteria for the ISO Controlled Grid which the Participating TOs will use in their transmission planning and expansion studies or decisions.

3.2.2 Transmission Planning and Coordination.

The ISO shall actively participate with each Participating TO and the other Market Participants in the ISO Controlled Grid planning process in accordance with the terms of this ISO Tariff and the Transmission Control Agreement.

3.2.2.1 Each Participating TO with a PTO Service Territory shall develop annually a transmission expansion plan covering the next five years plus a ten-year case for the Loads that are geographically embedded within its PTO Service Territory and are within the ISO Control Area, even if such Loads are served by another Participating TO. Such Participating TO shall coordinate with the ISO and other Market Participants in the development of such plan. The Participating TO shall be responsible for ensuring that its transmission expansion plan meets all Applicable Reliability Criteria.

3.2.2.2 The ISO shall review the Participating TOs' transmission expansion plans for the PTO Service Territory, whether or not such plans are subject to Section 3.2.2.1, to ensure that each Participating TO's expansion plans meet the Applicable Reliability Criteria. The Participating TO will provide the necessary assistance and information as part of the coordinated planning process to the ISO to enable it to carry out its own studies for these purposes. If the ISO finds that the Participating TO's plan or projects do not meet the Applicable Reliability Criteria, the ISO will provide comments and the Participating TO will reassess its plans, as appropriate. The ISO may also propose new projects or suggest project changes *(e.g.*, timing, project size) for consideration by the Participating TO. Changes or additions made by the ISO and accepted by the TO will be included in the Participating TO's expansion plan. Changes or additions not accepted in the coordinated planning process will be resolved through the ISO ADR Procedure.

3.2.2.3 The Participating TO will act as a Project Sponsor for Participating TO proposed economic or reliability projects that are included in its expansion plan. The Participating TO shall provide to the ISO any information that the ISO requires to enable the ISO to comply with WECC and any other applicable regional coordination requirements pursuant to Section 3.2.6.

3.2.2.4 The ISO will be a member of the WECC and other applicable regional organizations and participate in WECC's operation and planning committees, and in other applicable regional coordinated planning processes. Neither the ISO 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 the ISO ADR Procedure.

3.2.3 Studies to Determine Facilities to be Constructed.

Where a Participating TO is obligated to construct or expand facilities in accordance with this ISO Tariff or where the ISO or any Market Participant requests that a Facility Study be carried out, the Participating TO (in coordination with the ISO or the relevant Market Participants as the case may require), shall perform the necessary study or studies to determine the appropriate facilities to be constructed in accordance with the terms set forth in the TO Tariff. The scope of and assumptions for any studies requested by a Project Sponsor of a transmission addition or upgrade on economic grounds must be acceptable to the Project Sponsors and the ISO. Any dispute relating to a Facility Study Agreement (including any dispute over the scope of the study or its assumptions) shall be resolved through the ISO ADR Procedures.

3.2.4 Operational Review.

The ISO will perform an operational review of all facilities that are to be connected to, or made part of, the ISO Controlled Grid to ensure that the facilities being proposed provide for acceptable operating flexibility and meet all its requirements for proper integration with the ISO Controlled Grid. If the ISO finds that such facilities do not provide for acceptable operating flexibility or do not adequately integrate with the ISO Controlled Grid, the Participating TO will reassess its determination of the facilities required to be constructed.

3.2.5 State and Local Approval and Property Rights.

3.2.5.1 The Participating TO shall be obligated to 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 transmission additions or upgrades required to be constructed in accordance with this ISO Tariff. This obligation includes the Participating TO's use of eminent domain authority, where provided by state law.

3.2.5.2 If the Participating TO cannot secure any such necessary approvals or property rights and consequently is unable to construct a transmission addition or upgrade, it shall promptly notify the ISO and the Project Sponsor and shall comply with its obligations under the TO Tariff to convene a technical meeting to evaluate alternative proposals. The ISO 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.

3.2.5.3 Where 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 ISO Tariff (including the use of eminent domain authority, where provided by state law) the ISO may confer on a third party the right to build the transmission addition or upgrade which shall enter into the Transmission Control Agreement in relation to such transmission addition or upgrade.

3.2.6 WECC and Regional Coordination.

The Project Sponsor will have responsibility for completing any applicable WECC requirements and other applicable regional coordination 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.

3.2.7 Cost Responsibility for Transmission Additions or Upgrades.

Cost responsibility for transmission additions or upgrades constructed pursuant to this Section 3.2 (including the responsibility for any costs incurred under Section 3.2.6) shall be determined as follows:

3.2.7.1 Where a Project Sponsor commits to pay the full cost of a transmission addition or upgrade as set forth in Section 3.2.1.1.2, the full costs shall be borne by the Project Sponsor.

3.2.7.2 Where the need for a transmission addition or upgrade is determined by the ISO or as a result of the ISO ADR Procedure as set forth in Section 3.2.1.1.3, 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.

3.2.7.3 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 attributable to the transmission addition or upgrade;

(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 9.5.3, provided that the Project Sponsor does not receive FTRs from the ISO in accordance with Section 9.4.3 of the ISO Tariff; and

(c) its share, as determined in subsection (d) below, of the Congestion revenues provided as calculated pursuant to Section 7.3.1.6 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 from the new rating for the upgraded transmission facility by the new rating for the upgraded transmission facility. The Participating TO's share of Wheeling, Congestion and FTR auction revenues for the upgraded 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 based on the physical addition to the transfer capability as determined through the regional reliability council process of the Western Electricity Coordinating Council or its successor.

3.2.7.4 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. 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.

3.2.8 Ownership of and Charges for Expansion Facilities.

3.2.8.1 All transmission additions and upgrades constructed in accordance with this Section 3.2 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.

3.2.8.2 Each Participating TO that owns or operates transmission additions and upgrades constructed in accordance with this Section 3.2 shall provide access to them and charge for their use in accordance with this ISO Tariff and its TO Tariff.

3.2.9 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 3.2 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 3.2.

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4. RELATIONSHIP BETWEEN ISO AND UDCS.

4.1 General Nature of Relationship Between ISO and UDCs.

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 and any other expressly applicable Sections of this ISO Tariff and the ISO Protocols as these may be amended from time to time. The ISO shall maintain a pro forma UDC Operating Agreement available for UDCs to enter into with the ISO.

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, have the right by agreement to delegate certain operational responsibilities to the relevant Participating TO or UDC pursuant to this Section 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.

4.2 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 2.3.3.

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:

4.3.1 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;

4.3.2 provide the ISO Outage Coordination Office each year with a schedule of upcoming maintenance that has a reasonable potential of impacting the ISO Controlled Grid in accordance with Section 2.3.3.5 of this ISO Tariff; and

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 System Emergencies.

4.4.1 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 the ISO Protocols.

4.4.2 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.

4.4.3 Under Frequency Load Shedding (UFLS).

4.4.3.1 Each UDC's agreement with the ISO shall describe the UFLS program for that UDC. The ISO and UDC shall review the UFLS program periodically to ensure compliance with Applicable Reliability Criteria.

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

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

4.4.3.4 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 4.4.3.1 to 4.4.3.3.

4.4.4 The ISO shall have the authority to direct a UDC 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 to shed Load in accordance with the prioritization schedule developed pursuant to Section 2.3.2.6. When ISO Controlled Grid conditions permit restoration of Load, the ISO shall restore Load according to the prioritization schedule developed pursuant to Section 2.3.2.6 hereof.

4.5 Electrical Emergency Plan (EEP).

4.5.1 The ISO shall in accordance with Section 2.3.2.4 hereof implement the Electrical Emergency Plan in consultation with the UDCs or other entities, at the ISO's discretion, when Energy reserve margins are forecast to be at the levels specified in the plan.

4.5.2 Each UDC will notify its End-Use Customers connected to its Distribution System of any voluntary curtailments notified to the UDC by the ISO pursuant to the provisions of the EEP.

4.5.3 Load Shedding

4.5.3.1 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.

4.5.3.2 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.

4.5.3.3 If a Load curtailment is required to manage System Emergencies, in any circumstances other than those described in Section 4.5.3.2, 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.

4.6 System Emergency Reports: UDC Obligations.

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

4.6.2 Each UDC shall cooperate with the ISO in the preparation of an Outage review pursuant to Section 2.3.2.9.

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.

4.8 Information Sharing.

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.

4.8.2 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.

4.8.3 Reports.

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.

4.8.3.2 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.

4.8.3.3 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.

4.8.4 Installation of and Rights of Access to UDC Facilities.

4.8.4.1 Installation of Facilities.

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.

4.8.4.1.2 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.

4.8.4.2 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.

4.8.4.3 Access During Emergencies.

Notwithstanding any provision in this Section 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.

4.9 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.

5. 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 5 and Section 2.3.2.

5.1 General Responsibilities.

5.1.1 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 2.3 and the requirements for the dispatch and testing of Ancillary Services specified in Section 2.5.

5.1.2 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.

5.1.3 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 2.3 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.

5.1.4 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.

5.1.4.1 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 5 and with Section MP 2.3.5 of the Metering Protocol 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.

5.1.5 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.

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

5.2.1 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 5.2, 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.

5.2.1.1 If the ISO, pursuant to Section 2.5.12(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 2.5.3.6), except that the ISO shall not be required to accept bids that exceed price caps imposed by the ISO or the FERC.

5.2.1.2 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 2.5.3.6) have been selected pursuant to Section 2.5.21, 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 5.2.1.2; 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 5.2.1.1. The ISO must provide the notice specified in paragraph (3) of this Section 5.2.1.2 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 2.5.3.6) 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 2.5.12 (“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.

5.2.2 [Not Used]

5.2.3 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.

5.2.4 [Not Used]-

5.2.5 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.

5.2.6 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.

5.2.7 Reliability Must-Run Charge. The ISO shall prepare and send to each Responsible Utility in accordance with Annex 1 to the ISO's Settlement and Billing Protocol 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 5.2.8. 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 5.2.7. 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 Annex 1 to the ISO's Settlement and Billing Protocol 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 5.2.7, Article 9 of the Reliability Must-Run Contract and Annex 1 to the ISO's Settlement and Billing Protocol. 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 5.27, Annex 1 to the ISO's Settlement and Billing Protocol 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 an any time. The ISO shall not modify this Section 5.27 or Annex 1 to the ISO Settlement and billing Protocol 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.

5.2.7.1 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 5.2.7.1.1, the Responsible Utility may deduct such amount from payment otherwise due under such ISO Invoice.

5.2.7.1.1 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 Annex 1 to the ISO's Settlement and Billing Protocol, 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.

5.2.7.1.2 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 5.2.7.1.2, 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.

5.2.7.1.3 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 12.2.2, of the ISO's performance of its obligations to Responsible Utilities under this Section 5.2.7 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.

5.2.7.1.4 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 Annex 1 to the Settlement and Billing Protocol, 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.

5.2.7.2 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 resoultion 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 nonpayments that result in payment defaults by the ISO under a Reliability Must-Run Contract. To that end, in the event of nonpayment 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.

5.2.7.3 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 5.2.7.3 is intended to cover the New Responsible Utility's outstanding liability for payments it is liable to make to the ISO under this Section 5.2.7, 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.

5.2.8 Responsibility for Reliability Must-Run Charge Except as otherwise provided in Section 5.2.8.1, 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.

5.2.8.1 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.

5.2.9 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 5.2.9, 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 5.2.9, 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 5.2.9 outside of the RMR Contract shall not be used to determine future RMR Contract Annual Service Limits. Payment for Dispatches pursuant to this Section 5.2.9 is governed by Section 11.2.4.2 of this Tariff.

5.3 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.

5.4 WECC Requirements.

5.4.1 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.

5.4.2 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 5.4.2 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.

5.4.3 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.

5.5 Outages.

5.5.1 Planned Maintenance.

Each Participating Generator shall comply with the applicable provisions of Section 2.3.3.

5.5.2 The ISO shall, on the basis of the information supplied by Participating Generators under Section 5.5.1 and other information available to the ISO, prepare and publish on WEnet forecast aggregate available Generation capacity and forecast Demand on an annual, quarterly and monthly basis in accordance with the provisions of the ISO Outage Coordination Protocol. In publishing these forecasts, the ISO shall identify any expected Congestion conditions caused by planned Outages of Participating Generators.

5.5.3 Forced Outages.

Procedures equivalent to those set out in Section 2.3.3 shall apply to all Participating Generators in relation to Forced Outages.

5.6 System Emergencies.

5.6.1 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 5.6.2, 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. It 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.

5.6.2 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 5.6.1.

5.6.3 [Not Used]

[Page Not Used]

5.7 Interconnection of New Facilities to the ISO Controlled Grid.

5.7.1 Applicability.

For purposes of this Section 5.7, a New Facility shall be:

(a) each 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 re-powered and increase the total capability of the power plant; and

(c) each existing Generating Unit connected to the ISO Controlled Grid that will be re-powered 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 trigger the application of Section 5.7.5(c).

The owner of a planned New Facility, or its designee, is referred to for purposes of this Section 5.7 as a New Facility Operator. Only New Facility Operators that have not submitted a Completed Interconnection Application, as defined under the applicable Interconnecting PTO's TO Tariff, to the Interconnecting PTO as of the effective date of this Section 5.7 are subject to its provisions.

5.7.2 Requests to Interconnect to the Distribution System.

Any request by a New Facility Operator to connect at distribution level voltage will be processed, as applicable, pursuant to the Wholesale Distribution Access Tariff of the Interconnecting PTO or CPUC Rule 21; provided, however, that the New Facility Operator shall be required to mitigate any adverse impact on reliability on the ISO Controlled Grid in accordance with Section 5.7.5. In addition, each Interconnecting PTO will provide to the ISO a copy of the System Impact Study used to determine the impact of a New Facility on the Distribution System and the ISO Controlled Grid pursuant to a request to interconnect under the applicable Wholesale Distribution Access Tariff.

5.7.3 Interconnection Application.

All 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.

5.7.3.1 Expedited Procedures For New Facilities.

A New Facility Operator may submit a Request for Expedited Interconnection Procedures in accordance with Section 5.7.3.1.1. The ISO will develop and post on the ISO Home Page the Planning Procedures applicable to such expedited processing of Interconnection Applications.

5.7.3.1.1 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 Section 5.7 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.

5.7.3.2 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.

5.7.3.3 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 or in the event that an applicant's identity becomes otherwise publicly known.

5.7.4 Interconnection.

5.7.4.1 Detailed Planning Procedures.

The provisions set forth in this Section 5.7 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. The ISO will develop, and post on the ISO Home Page, detailed procedures for updating the Planning Procedures.

5.7.4.2 Studies.

(a) Except as provided in Section 5.7.4.2(d), 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 5.7.4.4. 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 5.7.4.2.1 and 5.7.4.2.2. 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.

5.7.4.2.1 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.

5.7.4.2.2 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 5.7.4.2.1 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.

5.7.4.3 Execution of Interconnection Agreement.

Within 10 Business Days of receipt of a completed Facility Study, a New Facility Operator 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 5.7.4.2.1 and 5.7.4.2.2, 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.

5.7.4.4 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 5.7.4.4.1.

(c) For any New Facility Operator that has submitted a request to interconnect to a Interconnecting PTO prior to the date that FERC makes Section 5.7 effective, 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.

5.7.4.4.1 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 Section 5.7 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 5.7.4.4.1 within 30 calendar days of the date the decision on the dispute becomes final.

5.7.4.5 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.

5.7.5 Cost Responsibility of New Facility Operators.

(a) Each New Facility Operator shall pay the costs of required studies in accordance with Section 5.7.4.2 and the costs identified in this Section 5.7.5. 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 5.7.4.4.1(b). 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.

5.7.5.1 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 5.7.4.2.1. 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.

5.7.5.2 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.

5.7.6 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 5.7.4.3, 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 Section 5.7.

5.8 Recordkeeping; Information Sharing.

5.8.1 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.

5.8.2 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.

5.8.3 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.

5.8.4 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.

5.9 Access Right.

A Participating Generator shall, at the request of the ISO and upon reasonable notice, provide access to its facilities (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 5.4 of this ISO Tariff, or (iii) to obtain information relative to a Forced Outage.

5.10 Black Start Services.

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

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

5.10.3 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.

5.10.4 If the ISO has intervened in the market for Energy and/or Ancillary Services pursuant to Section 2.3.2.3, 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.

5.10.5 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.

5.11 Must-Offer Obligations

5.11.1 Applicability

The requirements of Section 5.11 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, 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 5.11.1 is referred to in the ISO Tariff as a "Must-Offer Generator." The requirements of this Section 5.11 shall apply to all non-hydroelectric Generating Units located in California that are owned or controlled by a Must-Offer Generator.

5.11.2 Available Generation

For the purposes of this Section 5.11, a 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 2.3 or 5.11.3 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 point as identified in the ISO's Final Hour-Ahead Schedule, (c) minus the Generating 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 Must-Offer Generator's Native Load.

5.11.3 Reporting Requirements for Non-Participating Generators

So that the ISO may determine the Available Generation of all Must-Offer Generators, 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 Unit's minimum operating level; (ii) the Unit's maximum operating level; and (iii) the 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 Must-Offer Generators. In addition, 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 5.11, 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.

5.11.4 Obligation To Offer Available Capacity

Except as set forth in Section 5.11.6, all 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 5.11.2.

5.11.5 Submission of Bids and Applicability of the Proxy Price

For each Operating Hour, Must-Offer Generators shall submit Supplemental Energy bids for all of their Available Generation to the ISO in accordance with Section 2.5.22.4. In addition, the ISO shall calculate for each gas-fired Must-Offer Generator, in accordance with Section 2.5.23, a Proxy Price for Energy.

If a Must-Offer Generator fails to submit a Supplemental Energy bid for any portion of its Available Generation for any BEEP Interval, the unbid quantity of the Must-Offer Generator's Available Generation will be deemed by the ISO to be bid at the Must-Offer Generator's Proxy Price for that hour if: (i) the applicable Generating Unit is a gas-fired unit and (ii) the Must-Offer Generator has provided the ISO with adequate data in compliance with Sections 2.5.23.3.3 and 5.11.3 for the applicable Generating Unit. For all other Generating Units owned or controlled by a Must-Offer Generator, the unbid quantity of the Must-Offer Generator's Available Generation will be deemed by the ISO to be bid to receive the BEEP Interval Ex Post Price. In order to dispatch resources providing Imbalance Energy in proper merit order, the ISO will insert this unbid quantity into the 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 Must-Offer Generator's Available Generation.

5.11.6 Waiver of Must-Offer Obligation

Must-Offer Generators may seek a waiver of the obligation to offer all available capacity, as set forth in Section 5.11.4 of this ISO Tariff, for one or more of their Generating Units.

All 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 capacity. If conditions permit, and at the ISO's non-discriminatory and sole discretion, the ISO may grant waivers and allow a Must-Offer Generator to remove one or more Generating Units from service.

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. 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). The ISO shall inform a Must-Offer Generator that its Waiver request has been approved, disapproved or revoked, and shall provide the Must-Offer Generator with the reason(s) for the decision, which reasons shall be non-discriminatory. The ISO will: (1) notify 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 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.

5.11.6.1 Recovery of Minimum Load Costs By Must-Offer Generators

5.11.6.1.1 Eligibility

Except as set forth below, Generating Units shall be eligible to recover Minimum Load Costs during Waiver Denial Periods. Units from 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 Must-Offer Generator has a Final Hour-Ahead Energy Schedule other than a Schedule to a unit-specific Demand ID used for the purpose of scheduling minimum load energy as set forth in Section 5.11.6, the Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. When, on an hourly basis, a Must-Offer Generator generating at minimum load in compliance with the must-offer obligation, produces a quantity of Energy that varies from its minimum operating level by more than the greater of: (i) five (5) MWh or (ii) an hourly Energy amount equal to three (3) percent (%) of the unit's maximum operating output, the Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. Subject to the foregoing eligibility restrictions set forth in this section, the ISO shall pay to an otherwise eligible Must-Offer Generator the Minimum Load Costs for each hour within a Waiver Denial Period that the Generating Unit runs at minimum load in compliance with the must-offer obligation and for each hour that an otherwise eligible Must-Offer Generator generates in compliance with an ISO Dispatch Instruction.

5.11.6.1.2 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 2.5.23.3.3) at the unit's minimum operating level as set forth in Schedule 1 of the Generating Unit's Participating Generator Agreement 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 Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas; and 2) the product of the unit's minimum operating level as set forth in Schedule 1 of the Generating Unit's Participating Generator Agreement and $6.00/MWh.

5.11.6.1.2.1 Operating Must-Offer Generating Units above Minimum Load

If, during a Waiver Denial Period, the ISO requires that a Generating Unit operate at a level above its minimum load operating so as to be able to respond effectively to real time Dispatch Instructions, the ISO shall operate that Generating Unit at such an operating level. The ISO shall pay the Minimum Load Costs set forth in Section 5.11.6.1.2 for the amount of the Generating Unit's Minimum Load. For the amount of Energy above Minimum Load to the Unit's required operating level, the ISO shall pay the greater of the product of such amount of Energy and (1) the price for instructed Imbalance Energy or (2) the sum of (a) the product of (i) the Generating Unit's incremental heat rate at the required operating level and (ii) the proxy figure for natural gas costs set forth in Section 2.5.23.4 and (b) $6.00.

5.11.6.1.3 Invoicing Minimum Load Costs

The ISO shall determine each Scheduling Coordinator's Minimum Load Costs and make payments for these costs as part of the ISO's market settlement process. Scheduling Coordinators may submit to the ISO data detailing the hours for which they are eligible to recover Minimum Load Costs. Scheduling Coordinators who elect to submit data on hours they are eligible to recover Minimum Load Costs must: 1) use the Minimum Load Cost invoice template posted on the ISO Home Page, and 2) submit the invoice on or before fifteen (15) Business Days following the last Trading Day in the month in which such costs were incurred, except that Scheduling Coordinators seeking reimbursement for Minimum Load Costs incurred between May 29, 2001, and June 30, 2002 must submit their data to the ISO by August 5, 2002.

5.11.6.1.4 Allocation of Minimum Load Costs

Minimum Load Costs for the total number of eligible hours for each unit shall be evenly divided over all such eligible hours. For each such hour, the total Minimum Load Costs shall be allocated to each Scheduling Coordinator in proportion to the sum of that Scheduling Coordinator's Load and Demand within California outside the ISO Control Area that is served by exports to the 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.

5.11.6.1.5 Payment Of Available Capacity Under The Must-Offer Obligation

Available capacity 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 5.11.6.1.1, that the unit generated above minimum load in compliance with ISO Dispatch Instructions.

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5.12 [Not Used]

5.13 Energy Bids.

5.13.1 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 Dispatch Protocol 8.6.4, and (b) the Real-Time Economic Dispatch (10-minute

Imbalance Energy market). 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.

5.13.2 Energy Bid Submission.

5.13.2.1 Real Time Market. Bids shall be submitted for use in the real-time Hourly Pre-Dispatch in DP 8.6.4(j) and the Real-Time Economic Dispatch up to sixty (60) minutes prior to the Operating Hour. Resources required to offer their Available Generation in accordance with Section 5.11.4 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 5.11.4. Resources not required to offer their Available Generation in accordance with Section 5.11.4 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 5.11.4 may voluntarily submit Energy Bids. Submitted Energy Bids shall be subject to the Damage Control Bid Cap as set forth in Section 28.1 and to the Mitigation Measures set forth in Appendix A to the Market Monitoring and Information Protocol.

5.13.2.2 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.

5.13.3 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 2.5.23.3.4 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.

6. TRANSMISSION SYSTEM INFORMATION AND COMMUNICATIONS.

6.1 WEnet.

6.1.1 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.

6.1.2 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.

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

6.1.2.2 The ISO shall provide public information over WEnet which shall include, at a minimum, but not limited to:

6.1.2.2.1 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.

6.1.2.2.2 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.

6.1.2.2.3 Ex Post Information:

(a) Date;

(b) Hour; and

(c) Hourly Ex Post Price.

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

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

6.1.2.5 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.

6.1.2.6 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.

6.2 Reliable Operation of the WEnet.

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

6.2.2 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.

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

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

6.3.1.1 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;

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

6.3.2 Each representative specified pursuant to Section 6.3.1 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.

6.3.3 The details required under this Section 6.3 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.

6.4 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.

6.5 Confidentiality.

All information posted on WEnet shall be subject to the confidentiality obligations contained in Section 20.3 of this ISO Tariff.

6.6 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.

7. TRANSMISSION PRICING.

7.1 Access Charges.

All Market Participants withdrawing Energy from the ISO Controlled Grid shall pay Access Charges in accordance with this Section 7.1 and Appendix F, Schedule 3. 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 7.1 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 Section 6 and 8 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. If a Participating TO 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. 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.

7.1.1 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.

7.1.2 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 7.1.3.

7.1.3 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.

7.1.3.1 [Not Used]

7.1.3.2 [Not Used]

7.1.3.3 [Not Used]

7.1.3.4 [Not Used]

7.1.3.5 [Not Used]

7.1.4 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. Schedules that include Wheeling transactions shall be subject to the Congestion Management procedures and protocols in accordance with Sections 7.2 and 7.3.

7.1.4.1 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.

7.1.4.2 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.

7.1.4.3 Disbursement of Wheeling Revenues. The ISO shall collect and pay to Participating TOs and other entities as provided in Section 3.2.7.3 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 3.2.7.3 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:

7.1.4.3.1 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 3.2.7.3.

7.1.4.3.2 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 7.1.4.3.1.

7.1.4.4 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 7.1.4.4 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”.

7.1.5 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.

7.1.6 [Not Used]

7.1.6.1 Tracking Account. If the Access Charge rate methodology implemented pursuant to Section 7.1 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.

7.1.6.2 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 3.2.7.

7.1.6.3 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.

7.2 Zonal Congestion Management.

7.2.1 The ISO Will Perform Congestion Management.

7.2.1.1 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.

7.2.1.2 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.

7.2.1.3 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.”

7.2.1.4 Elimination of Potential Transmission Congestion. The ISO's Day-Ahead and Hour-Ahead scheduling procedures will eliminate potential Inter-Zonal Congestion by:

7.2.1.4.1 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

7.2.1.4.2 rescheduling Scheduling Coordinators' resources (but so that Intra-Zonal transmission limits are not violated) using the Adjustment Bids that are submitted by Scheduling Coordinators.

7.2.1.5 Elimination of Real-Time Inter-Zonal Congestion. In its management of Inter-Zonal Congestion in real time, the ISO will make the minimum amount of adjustment necessary to relieve Inter-Zonal Congestion by incrementing or decrementing Generation or Demand, as necessary, based on the merit order stack in accordance with Dispatch Protocol Section 8.3.

7.2.2 General Requirements for the ISO's Congestion Management. The ISO's Congestion Management in the Day-Ahead Market and Hour-Ahead Market shall:

7.2.2.1 only operate if the Scheduling Coordinators do not eliminate Congestion voluntarily;

7.2.2.2 adjust the Schedules submitted by Scheduling Coordinators only as necessary to alleviate Congestion;

7.2.2.3 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;

7.2.2.4 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;

7.2.2.5 [Not Used]

7.2.2.6 publish information and, if requested by Scheduling Coordinators will provide a mechanism to facilitate voluntary trades among Scheduling Coordinators;

7.2.2.7 [Not Used]

7.2.2.8 adjust the Schedules submitted by Scheduling Coordinators on the basis of any price information voluntarily submitted through their Adjustment Bids; and

7.2.2.9 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.

7.2.3 Use of Computational Algorithms for Congestion Management and Pricing.

The ISO will use computer optimization algorithms to implement its Congestion Management process.

7.2.4 Adjustment Bids Will Be Used by the ISO to Manage Congestion.

7.2.4.1 Uses of Adjustment Bids by the ISO.

7.2.4.1.1 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 and to reflect the Scheduling Coordinators' implicit values for Inter-Zonal Interface capacity.

7.2.4.1.2 The Adjustment Bids will be used by the ISO to determine the marginal value associated with each Congested Inter-Zonal Interface.

7.2.4.1.3 [Not used]

7.2.4.1.4 The ISO shall also use incremental Adjustment Bids from Generating Units and Adjustment Bids from other resources in the ISO's real-time system operation 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.

7.2.4.1.5 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.

7.2.4.2 Submission of Adjustment Bids.

7.2.4.2.1 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.

7.2.4.2.2 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.

7.2.4.2.3 The Scheduling Coordinator's preferred operating point for each resource must be within the range of the Adjustment Bids.

7.2.4.2.4 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.

7.2.4.2.5 During the ISO's Day-Ahead scheduling process, the MW range of the Adjustment Bid, but not the price values, may be changed.

7.2.4.2.6 An Adjustment Bid shall constitute a standing offer to the ISO until it is withdrawn.

7.2.4.2.7 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.

7.2.5 Inter-Zonal Congestion Management.

7.2.5.1 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.

7.2.5.2 The purpose of Inter-Zonal Congestion Management is to allocate the use of, and determine the marginal value of, active Inter-Zonal Interfaces. Inter-Zonal Congestion Management will comply with the requirements stated in Sections 7.2.2, 7.2.4 and 7.2.5.

7.2.5.2.1 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.

7.2.5.2.2 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.

7.2.5.2.3 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.

7.2.5.2.4 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.

7.2.5.2.5 All of the ISO's calculations will treat each Settlement Period independently of the other Settlement Periods in the Trading Day.

7.2.5.2.6 **[Not Used]**

7.2.5.2.7 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.

7.2.5.2.8 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.

7.2.5.2.9 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.

7.2.6 Intra-Zonal Congestion Management.

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 7.2.6, as provided for in the MSS Agreement.

7.2.6.1 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 A to the Market Monitoring and Information Protocol. 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 7.2.6.1 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 7.2.6.1 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 7.2.6.1 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 2.5.23.3.7.6.

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.

7.2.6.1.1 Decremental Bid Reference Levels. Decremental bid reference levels shall be determined for use in managing Intra-Zonal Congestion as set forth above in Section 7.2.6.1.

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

1. Excluding proxy bids, mitigated bids, and bids used out of merit order for managing Intra-Zonal Congestion, the accepted decremental bid, or the lower of the mean or the median of a resource's accepted decremental bids if such a resource has more than one accepted decremental bid in competitive periods over the previous 90 days for peak and off-peak periods, adjusted for monthly changes in fuel prices using the proxy figure for natural gas prices posted on the ISO Home Page. For the purposes of this Section 7.2.6.1.1, 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 deemed 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 28.1.3 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 5.11.5 (based on the incremental heat rate submitted to the independent entity responsible for determining reference prices, adjusted for gas prices, 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; 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.

7.2.6.1.2 [Not Used]

7.2.6.1.3 [Not Used]

7.2.6.1.4 [Not Used]

7.2.6.1.5 [Not Used]

7.2.6.1.6 [Not Used]

7.2.6.2 Incremental Bids. With regard to incremental bids, except as provided in Sections 5.2, 7.2.6.1 and 11.2.4.2, the ISO will perform Intra-Zonal Congestion Management in real time using available Adjustment Bids and Imbalance Energy bids, based on their effectiveness and in merit order, to minimize the cost of alleviating Congestion. In the event no Adjustment Bids or Imbalance Energy bids are available, the ISO will exercise its authority to direct the Redispatch of resources as allowed under the Tariff, including Section 2.4.4.

7.2.6.3 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 7.3.2.

7.2.6.4 Dispatch of Hydroelectric Resources for Congestion. If the ISO must dispatch hydroelectric resources for which no Supplemental Energy bids have been submitted to manage Congestion, the ISO shall do so only after dispatching all other reasonably effective resources that could be used to manage the Congestion.

7.2.7 Creation, Modification and Elimination of Zones.

7.2.7.1 Active Zones. The Active Zones are as set forth in Appendix I to this ISO Tariff.

7.2.7.2 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.

7.2.7.2.1 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.

7.2.7.2.2 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 7.2.7.2.1.

7.2.7.2.3 [Not Used]

7.2.7.2.4 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.

7.2.7.2.5 The ISO may change the criteria for establishing or modifying Zone boundaries, subject to regulatory approval by the FERC.

7.2.7.3 Active and Inactive Zones.

7.2.7.3.1 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 7.2.7.3.4.

7.2.7.3.2 The Congestion Management described in this Section 7.2, and the Usage Charges stemming from the application of these procedures, shall not apply to Inter-Zonal Interfaces with Inactive Zones.

7.2.7.3.3 [Not Used]

7.2.7.3.4 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.

7.2.7.3.5 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.

7.3 Usage Charges and Grid Operations Charges.

7.3.1 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 2.4.4.4.4.1, 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.

7.3.1.1 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 7.2.5, 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.

7.3.1.2 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 7.2.

7.3.1.2.1 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.

7.3.1.2.2 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.

7.3.1.2.3 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.

7.3.1.3 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 7.3.1.3.1 through 7.3.1.3.4.

7.3.1.3.1 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.

7.3.1.3.2 The default Usage Charge will be calculated, in accordance with this Section 7.3.1.3, 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).

7.3.1.3.3 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 7.3.1.3.2 will be set at $0/MWh.

7.3.1.3.4 The ISO will develop and implement a procedure for posting default Usage Charges on the WEnet or ISO Home Page.

7.3.1.3.5 If the Congestion Management software is not capable of calculating the default Usage Charge upon the ISO Operations Date in accordance with Sections 7.3.1.3.1 through 7.3.1.3.4, 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 7.3.1.3.1 through 7.3.1.3.4 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.caiso.com or such other Internet address as the ISO may publish from time to time.

7.3.1.4 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 7.3.1.2 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.

7.3.1.5 Determination of Usage Charges to be Paid to Scheduling Coordinators Who Counter-Schedule.

7.3.1.5.1 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 7.3.1.2 for that particular hour, multiplied by the Scheduling Coordinator's scheduled flows.

7.3.1.5.2 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, for 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.

7.3.1.6 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 7.3.1.7 of the ISO Tariff, paid to: (i) FTR Holders, in accordance with Section 9.6; 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 3.2.7.3. 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.

7.3.1.7 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 3.2.7.3, 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 7.3.1.6, 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 3.2.7.3, 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.

7.3.2 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 7.2.6, will be paid or charged as set forth in Settlements and Billing Protocol Appendix 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.

7.4 Transmission Losses.

7.4.1 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 7.4.

7.4.2 Determination of Transmission Losses.

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 7.4.3. 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.

7.4.2.1 Procedures for Calculating Generation Meter Multiplier.

7.4.2.1.1 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. 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 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.

7.4.2.1.2 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 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.

7.4.2.2 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.

7.4.2.2.1 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.

7.4.2.2.2 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.

7.4.2.2.3 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.

7.4.3 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.

7.5 FERC Annual Charges.

7.5.1 Obligation for FERC Annual Charges.

7.5.1.1 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 7.5. Such assessment shall be levied monthly against all Scheduling Coordinators based upon each Scheduling Coordinator's metered Demand and exports.

7.5.1.2 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 Approved Credit Rating, as defined with respect to either payment of the Grid Management Charge, or payment of other charges, or shall maintain security in accordance with Section 2.2.3.2.

7.5.2 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.

7.5.3 Determination of the FERC Annual Charge Recovery Rate.

7.5.3.1 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.

7.5.3.2 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 7.5.3.4.

7.5.3.3 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.

7.5.3.4 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 7.5.3.2. 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 2.2 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.

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

In addition to the surcharges or credits permitted under Sections 7.5.3 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.

8. GRID MANAGEMENT CHARGE.

8.1 ISO's Obligations.

8.1.1 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.

8.1.2 [Not Used]

8.2 Costs Included in the Grid Management Charge.

8.2.1 [Not Used]

8.2.2 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").

8.2.3 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").

8.2.4 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").

8.3 Allocation of the Grid Management Charge Among Scheduling Coordinators.

The costs recovered through the Grid Management Charge shall be allocated to the seven 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 8.4. The seven service charges are as follows:

(1) Core Reliability Services Charge,

(2) Energy Transmission Services Net Energy Charge,

(3) Energy Transmission Services Uninstructed Deviations Charge,

(4) Forward Scheduling Charge,

(5) Congestion Management Charge,

(6) Market Usage Charge, and

(7) Settlements, Metering, and Client Relations Charge.

The seven 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.

8.3.1 Core Reliability Services Charge.

The Core Reliability Services Charge for a Scheduling Coordinator is calculated using the Scheduling Coordinator's metered non-coincident peak hourly Demand during the month (in megawatts). The rate for the Core Reliability Services 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, according to the formula in Appendix F, Schedule 1, Part A of this Tariff.

8.3.2 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.

8.3.3 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.

8.3.4 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 MW, submitted to the scheduling infrastructure/scheduling application system. 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.

8.3.5 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.

8.3.6 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.

8.3.7 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.

8.4 Calculation and Adjustment of the Grid Management Charge.

The seven charges set forth in Section 8.3 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 seven ISO service charges to obtain a total revenue requirement. This revenue requirement is allocated among the seven 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 8.3. 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 make an informational filing with the FERC each year, before the adjusted rates go into effect, as described in Appendix F, Schedule 1, Part D of this Tariff, 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 8.5), 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. 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.

8.4.1 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.

8.5 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, Energy Transmission Services, Forward Scheduling, Congestion Management, Market Usage, and Settlements, Metering and Client Relations). 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.

8.6 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.

9. FIRM TRANSMISSION RIGHTS

9.1 General

9.1.1 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 9.3, with the rights and other characteristics described in Sections 9.2, 9.6, 9.7 and 9.8, and through the processes described in Section 9.4. Proceeds of the ISO's auction of FTRs shall be distributed as described in Section 9.5. The owners of FTRs shall be entitled to share in Usage Charge revenues associated with Inter-Zonal Congestion in accordance with Section 9.6, and to scheduling priority in the event of Congestion in the Day-Ahead Market, as described in Section 9.7. For the purpose of Section 9, the term “Zone” shall be construed to mean both “Zone” and “Scheduling Point.”

9.2 Characteristics of Firm Transmission Rights

9.2.1 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 9.6. 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 7.3.1.5.1 to a Scheduling Coordinator that counter-schedules from the designated originating Zone to the designated receiving Zone.

9.2.2 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 9.3.

9.2.2.1 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.

9.2.2.2 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.

9.2.3 Each FTR shall be issued in the denomination of 1 MW. The initial release of FTRs shall start with the hour beginning at 12:00 a.m., on February 1, 2000 and end with the hour beginning at 11:00 p.m., on March 31, 2001. 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.

9.2.4 The portion of the Usage Charges to which the FTR Holder is entitled shall be determined in accordance with Section 9.6.

9.2.5 FTR Holders shall be entitled to priority in the scheduling of Energy in the Day-Ahead Market as specified in Section 9.7.

9.2.6 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 9.4, 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.

9.2.7 All entities which acquire FTRs by participating in the ISO's auction of FTRs, as described in Section 9.4, directly from the ISO pursuant to Section 9.4.3, 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.

9.3 Maximum Number of Firm Transmission Rights

9.3.1 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.

9.4 Issuance of Firm Transmission Rights by the ISO

9.4.1 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 9.4.2, 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 9.4.2. 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.

9.4.2 The ISO shall conduct the auction of FTRs through the following procedures:

9.4.2.1 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 ration 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 9.4.2.3;

(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 9.2.6;

(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.

9.4.2.2 On or before the date specified in Section 9.4.2.1(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 9.4.2.1(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 9.4.2.1(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.

9.4.2.3 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 9.4.2.1(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 9.4.2.1(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.

9.4.2.4 Subject to Section 9.4.2.5, 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.

9.4.2.5 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 9.4.2.4 (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.

9.4.2.6 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 9.4.2.1(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.

9.4.2.7 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 9.4.2.6) and the total quantity of FTRs awarded to that FTR Bidder in that FTR Market (determined in accordance with Section 9.4.2.4 or Section 9.4.2.5, 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 9.2.6 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.

9.4.2.8 The ISO shall post on the ISO Home Page the prices at which FTRs are sold in each FTR Market through the primary auction.

9.4.3 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. 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. 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.

9.5 Distribution of Auction Revenues Received by the ISO for Firm Transmission Rights

9.5.1 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 9.4 shall be allocated and paid by the ISO to the Participating TO that is entitled in accordance with Section 7.3.1.6 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.

9.5.2 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.

9.5.3 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 3.2.7.1 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 3.2.7.3 (d).

9.6 Distribution of Usage Charges to FTR Holders

9.6.1 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 9.6.3.

9.6.2 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 9.6.1.

9.6.3 When the Day-Ahead scheduling capability of an Inter-Zonal Interface and direction is less than its scheduling capacity, determined in accordance with Section 9.3, 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 7.3.1.6 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 9.3, prior to the Day-Ahead Market, the entitlements of FTR Holders associated with that FTR Market to Usage Charge revenues shall not be increased.

9.6.4 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 7.3.1.7, the provisions of this Section 9.6 shall continue to apply, and FTR Holders shall be required to pay the ISO these amounts.

9.6.5 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.

9.7 Scheduling Priority of FTR Holders

9.7.1 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 9.7, 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.

9.7.2 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 7.2.4.

9.7.2.1 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.

9.7.3 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 9.6.3, the priority scheduling rights of FTR Holders, as described in Section 9.7.2, 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.

9.7.4 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 9.7.2.1 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 9.8.

9.8 Assignment of Firm Transmission Rights

9.8.1 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 9.2.7. 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 9.7, an FTR must be registered with the ISO.

9.8.2 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.

9.8.3 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.

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.

10.2 Responsibilities of ISO Metered Entities

10.2.1 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 the ISO metering protocols. Pursuant to this obligation, the ISO shall establish revenue metering protocols for such ISO Metered Entities.

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 the ISO metering protocols. 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 and the ISO metering protocols.

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 these Sections 10.1 to 10.5 and the ISO metering protocols. 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 the ISO metering protocols. 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 these Sections 10.1 to 10.5 and the ISO metering protocols.

10.2.5 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. ISO Metered Entities shall ensure compliance with the metering protocols to be established by the ISO pursuant to Section 10.2.1. 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 the ISO metering protocol. 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. If any Scheduling Coordinator does not have the ability to poll the ISO's revenue meter data acquisition and processing system as at the ISO

Operations Date, that Scheduling Coordinator shall have a period of up to 12 months from the ISO Operations Date in which to install the necessary equipment to enable it to poll directly the ISO revenue meter data acquisition and processing system. 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 the ISO metering protocols.

10.2.6 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.

10.3 Meter Service Agreements for ISO Metered Entities.

10.3.1 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 the ISO metering protocols. The meter service agreement and the ISO metering protocols 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.

10.3.2 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.

10.3.3 Availability of Meter Data.

The meter service agreement and the ISO metering protocols shall set out the ISO's requirements with regard to the frequency which it requires Meter Data to be made available to the ISO revenue meter data acquisition and processing system.

10.3.4 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.

10.3.5 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.

10.4 Low Side Metering.

Generators may, with the prior written approval of the ISO, install meters at the low voltage side of the connecting transformer. Such approval shall be given only if the ISO is satisfied that adequate accuracy and security of Meter Data obtained can be assured.

Meter service agreements related to Generators utilizing low voltage side metering shall set out ISO approved transformer loss correction factors to be applied by the Generator. The ISO has the sole authority to require and approve any and all other relevant metering system correction factors associated with an ISO Metered Entity.

10.5 Audit, Testing Inspection and Certification Requirements.

10.5.1 ISO Metered Entity Certification Testing and Audits.

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.

10.5.2 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 ISO metering protocols. 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.

10.6 Metering for Scheduling Coordinator Metered Entities.

10.6.1 Applicability.

The requirements set forth in this Section 10.6 shall apply only to Scheduling Coordinators representing Scheduling Coordinator Metered Entities.

10.6.2 Responsibilities of Scheduling Coordinators and the ISO.

10.6.2.1 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 10.6.3. 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.

10.6.2.2 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 in accordance with the ISO metering protocols and submit this data to the ISO in accordance with the ISO metering protocols.

10.6.2.3 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.

10.6.2.4 Communication of Meter Data. Each Scheduling Coordinator shall submit Settlement Quality Meter Data for Scheduling Coordinator Metered Entities to the ISO in accordance with the ISO metering protocols.

10.6.3 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.

10.6.4 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 and the ISO metering protocols.

10.6.5 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.

10.6.6 Collection of Meter Data.

10.6.6.1 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 10.6 and the ISO metering protocols.

10.6.6.2 Certification of Meters. Scheduling Coordinators shall ensure that revenue meters and related metering facilities of those Scheduling Coordinator MeteredEntities 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, certified in accordance with the ISO metering protocols. 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 and the ISO metering protocols. 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.

10.6.7 Meter Service Agreements for Scheduling Coordinator Metered Entities.

10.6.7.1 Requirement for Meter Service Agreements. 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 10.6.

10.6.7.2 [Not Used]

10.6.7.3 [Not Used]

10.6.7.4 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.

10.6.7.5 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.

10.6.7.6 [Not Used]

10.6.7.7 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.

10.6.7.8 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 10.6.

10.6.8 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.

10.6.9 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.

11. ISO SETTLEMENTS AND BILLING.

11.1 Settlement Principles.

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

(9) Reliability Must-Run Charges; and

(10) Default Interest Charges.

11.2 Calculations of Settlements.

The ISO shall calculate, account for and settle 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 Section 8 of this ISO Tariff.

11.2.2 Grid Operations Charge.

The Grid Operations Charge will be levied in accordance with Section 7.3.2 of this ISO Tariff.

11.2.3 Ancillary Services

The ISO shall calculate, account for and settle charges and payments for Ancillary Services as set out in Sections 2.5.27.1 to 4, and 2.5.28.1 to 4 of this ISO Tariff.

11.2.4 Imbalance Energy.

The ISO shall calculate, account for and settle Imbalance Energy in the Real Time Market for each Settlement Period for the relevant Zone or Scheduling Point within the ISO Controlled Grid.

11.2.4.1 Net Settlements for Uninstructed Imbalance Energy.

Uninstructed Imbalance Energy attributable to each Scheduling Coordinator for each Settlement Period in the relevant Zone 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 BEEP Interval of each Settlement Period equal to the product of the net deviation in the Zone or Zones, as appropriate, and the appropriate BEEP Interval Ex Post Price determined in accordance with Section 2.5.23.2.1.

The ISO shall develop protocols and procedures for the monitoring of persistent intentional excessive imbalances by Scheduling Coordinators and for the imposition of appropriate sanctions and/or penalties to deter such behavior.

Not withstanding the foregoing or any other provision in this Tariff, Uninstructed Imbalance Energy attributable to any Scheduling Coordinator for any System Resource Dispatched by the ISO shall be settled at the appropriate Instructed Imbalance Energy BEEP Interval Ex Post Price determined in accordance with Section 2.5.23.2.1.

11.2.4.1.1 Settlement for Instructed Imbalance Energy

Instructed Imbalance Energy attributable to each Scheduling Coordinator in each Settlement Period t in the relevant Zone 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 BEEP Interval of each Settlement Period in accordance with Section 2.5.23.

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 2.5.23.2.2 (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 Interconnection 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 BEEP Interval, and

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

For each BEEP 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 BEEP 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 2.5.23.3.7.6 and collected in accordance with Section 2.5.23.3.7.1.

11.2.4.2.2 Allocation of Above-MCP Costs

For each BEEP Interval, the above-MCP costs 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. Each Scheduling Coordinator's charge shall be the lesser of:

(a) the pro rata share of the total above-MCP costs 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 BEEP Interval and a weighted average price. The weighted average price is equal to the total above-MCP costs divided by the MWh delivered as a result of ISO instructions with a cost component above the MCP.

The difference between ISO charges to Scheduling Coordinators with Net Negative Uninstructed Deviations and the total above-MCP costs incurred by the ISO due to Instructed Imbalance Energy and Dispatch Instructions for reasons other than for a transmission facility outage or a location-specific requirement, as such difference is reduced pursuant to Section 11.2.4.1.2, shall be allocated amongst all Scheduling Coordinators in that BEEP Interval pro rata based on their metered Demand, including Exports.

The Scheduling Coordinator shall be exempt from the allocation of above-MCP costs in a BEEP Interval if the Scheduling Coordinator has sufficient incremental Energy bids from physically available resources in the Imbalance Energy market to cover their Net Negative Uninstructed Deviation in the given interval and the prices of such Energy bids do not exceed the applicable maximum bid level as set forth in Section 28.1.2 of this Tariff.

11.2.4.3 Unaccounted For Energy (UFE)

UFE is treated as Imbalance Energy. For each Settlement Period 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 included in the net settlements for Imbalance Energy in Section 11.2.4.1. 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 Charges and Transition Charges will be levied in accordance with Section 7.1 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 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 ISO Protocols. In each Settlement Period such requirements are met, the Participating Intermittent Resource shall be exempt from the charges (payments) for Uninstructed Imbalance Energy. Instead, the net Uninstructed Imbalance Energy in each BEEP Interval 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 2.5.23.2.3 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 2.5.28.4 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 BEEP Interval deviations by each Participating Intermittent Resource were priced at the appropriate BEEP 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 BEEP 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 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.

11.2.4.6 [Not Used]

11.2.5 Usage Charges.

Usage Charges will be levied in accordance with Section 7.3.1 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 7.1.4 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 2.5.27.5, 2.5.27.6, 2.5.28.5 and 2.5.28.6 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 5.2.7 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 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;

(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 2.5.27.1. 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 2.3.5.1 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 2.3.5.1 in accordance with Section 2.3.5.1.8 of this ISO Tariff.

11.2.11 FERC Annual Charge Recovery Rate

The ISO shall calculate and levy the rates for recovery of FERC Annual Charges in accordance with Section 7.5 of this ISO Tariff.

11.2.12 [Not Used]

11.2.13 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 2.5.23.3.6 and 2.5.23.3.7 of this ISO Tariff.

11.2.14 The ISO shall calculate, charge and disburse all collected default Interest in accordance with the ISO Tariff Settlement and Billing Protocol Sections 2, 5, and 6.

11.3 Billing and Payment Process.

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 7.5 of this ISO Tariff.

11.3.3 [Not used]

11.3.4 [Not used]

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.

11.5 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 The ISO shall provide to each Scheduling Coordinator for validation a Preliminary Settlement Statement of charges payable to or owed by the Scheduling Coordinator within thirty-eight (38) Business Days of the relevant Trading Day, covering all Settlement Periods in that Trading Day.

11.6.1.2 Each Scheduling Coordinator 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.

11.6.1.3 Each Scheduling Coordinator 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 shall have the opportunity to review the terms of the Preliminary Settlement Statements that it receives. The Scheduling Coordinator 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 to which it relates, unless the ISO performs a Settlement re-run pursuant to Section 11.6.3 of this ISO Tariff.

11.7.3 Validation of Final Settlement Statements.

Each Scheduling Coordinator shall have the opportunity to review the Incremental Changes that appear on the Final Settlement Statement that it receives. The Scheduling Coordinator 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 to which it relates, unless the ISO performs a Settlement re-run pursuant to Section 11.6.3 of this ISO Tariff.

11.7.4 Recurring disputes or exceptions.

A Scheduling Coordinator 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. 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 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 shall be deemed to apply to every subsequent Preliminary and Final Settlement Statement provided to the Scheduling Coordinator 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.

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 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 2.2.3.2 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.

11.8.2.3 Such other accounts as the ISO deems necessary or convenient for the purpose of efficiently implementing the funds transfer system under this ISO Tariff.

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 ISO Creditors, 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.

11.9 Invoices.

The ISO shall prepare and send to each Scheduling Coordinator two invoices for each calendar month. The first invoice will be based on the Preliminary Settlement Statments 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, 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 are to be paid. 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.

11.10 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.

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 any guarantee, letter of credit or other credit support 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.

11.13 Payment to ISO Creditors.

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.

11.14 Using the ISO 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 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 2.2.3.2 of this ISO Tariff or serving demands on any defaulting Scheduling Coordinators with an Approved Credit Rating.

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.

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 11.13.

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.

11.18.3 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.

11.22 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 20.3.

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. 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.

11.24 ISO Payments Calendar.

11.24.1 Preparation.

No later than 31 October in each year, the ISO shall publish an ISO Payments Calendar showing, 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 7.1.4.3 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 WEnet.

12. AUDITS.

12.1 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:

12.2 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:

12.2.1 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.

12.2.2 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.

12.2.3 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.

12.2.4 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.

12.3 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.

12.4 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.

12.5 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.

12.6 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.

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. LIABILITY AND INDEMNIFICATION.

14.1 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.

14.2 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.

14.3 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.

14.4 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.

UNCONTROLLABLE FORCES.

15.1 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.

15.2 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.

16. ISO GRID OPERATIONS COMMITTEE; CHANGES TO ISO PROTOCOLS.

16.1 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.

16.2 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.

16.3 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 16. The details of the ISO Market Monitoring and Information Protocol are set forth in Appendix L, ”ISO Protocols”.

17. ASSIGNMENT.

Obligations and liabilities under this ISO Tariff and any SC 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 SC 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.

18. TERM AND TERMINATION.

18.1 This ISO Tariff, shall become effective on the date it is permitted to become effective by the FERC.

18.2 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.

19. 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 SC 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, SC 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 SC 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.

20. MISCELLANEOUS.

20.1 Notice.

20.1.1 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.

20.1.2 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 SC 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.

20.1.3 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 20.1 of this ISO Tariff and, in the case of the ISO Protocols, Section 16.2 of this ISO Tariff.

20.2 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.

20.3 Confidentiality.

20.3.1 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 20.3.2; 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).

20.3.2 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.

20.3.3 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 20.3.2; 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.

20.3.4 Disclosure

Notwithstanding anything in this Section 20.3 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 20.3, the ISO may disclose such information; provided, however, that as soon as the ISO learns of the disclosure requirement and prior to making suchdisclosure, 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) 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.

20.4 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.

20.5 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.

20.6 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.

20.7 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.

20.8 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.

21. GENERATION METER MULTIPLIERS.

21.1 Temporary Simplification Relating to GMM Loss Factors.

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.

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.

21.2.1 Pursuant to Subsections 21.3.1 and 21.3.2, 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.

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21.2.2 [Not used]

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 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. SCHEDULE VALIDATION TOLERANCES.

22.1 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.caiso.com or such other Internet address as the ISO may publish from time to time.

22.2 Application.

Notwithstanding any other provision in this Tariff, including the ISO Protocols, the temporary simplification measure specified in this Section 22 shall have effect until discontinued by a Notice of Full-Scale Operations issued by the Chief Executive Officer of the ISO.

22.3 Notices of Full-Scale Operations.

22.3.1 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 22, 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.

22.3.2 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.

23 METERED SUBSYSTEMS

23.1 General Nature of Relationship Between ISO and MSS

23.1.1 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 23, shall be considered an MSS Operator and shall have the rights and obligations set forth in this Section 23. 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.

23.2 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.

23.3 Coordinating Maintenance Outages of MSS Facilities. Each MSS Operator shall make appropriate arrangements to coordinate Outages of Generating Units in accordance with Section 5. 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 2.3.3. The ISO will coordinate Outages of other Participating TOs transmission facilities that may affect the MSS.

23.4 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 and Section 2.3.2. 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:

23.4.1 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 23, until the MSS Operator demonstrates the ability and willingness to so operate and maintain its facilities;

23.4.2 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 2.3.3.5;

23.4.3 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;

23.4.4 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;

23.4.5 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 2.5.28.6; and

23.4.6 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.

23.5 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.

23.5.1 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.

23.5.2 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.

23.6 System Emergencies.

23.6.1 In the event a System Emergency occurs or the ISO determines that a System Emergency is threatened or imminent, 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.

23.6.2 During a System Emergency, 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.

23.6.3 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.

23.7 Under Frequency Load Shedding (UFLS).

23.7.1 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 MSS. The ISO and MSS Operator shall review the UFLS program periodically to ensure compliance with Applicable Reliability Criteria.

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

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

23.7.4 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 Sections 23.7.1 to 23.7.3 and Sections 4.4.3.1 to 4.4.3.3, inclusive.

23.7.5 The ISO shall have the authority to direct a 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 MSS Operator to shed Load in accordance with the prioritization schedule developed pursuant to Sections 2.3.2.6 and 4.5. When ISO Controlled Grid conditions permit restoration of Load, the ISO shall restore Load according to the prioritization schedule developed pursuant to Section 2.3.2.6 hereof. The MSS Operator shall restore Load internal to the MSS.

23.8 Electrical Emergency Plan (EEP).

23.8.1 The ISO shall in accordance with Section 2.3.2.4 hereof implement the Electrical Emergency Plan in consultation with 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.

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

23.8.3 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 4.5. Each MSS Operator shall be responsible for notifying its customers and Generators connected to its system of curtailments and service interruption.

23.9 System Emergency Reports: MSS Obligations.

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

23.9.2 Each MSS Operator shall cooperate with the ISO in the preparation of an Outage review pursuant to Section 2.3.2.9.

23.10 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.

23.11 Ancillary Service Obligations for MSS.

23.11.1 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.

23.11.2 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.

23.12 Load Following

23.12.1 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 23.12.2. The Scheduling Coordinator for an MSS Operator that chooses to follow its Load in accordance with this Section 23.12 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.

23.12.2 Under the circumstances described in Section 23.12.1, 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:

23.12.2.1 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.

23.12.2.2 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.

23.12.3 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.

23.12.3.1 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.

23.12.3.2 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.

23.12.3.3 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 8.3. Ancillary Service bids accepted by the ISO and Instructed Energy will be assessed the GMC ASREO.

23.13 Information Sharing.

23.13.1 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 4.8.1. 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.

23.13.2 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.

23.13.3 Reports.

23.13.3.1 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.

23.13.3.2 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.

23.13.3.3 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.

23.13.3.4 **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.

23.13.3.5 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.

23.14 Installation of and Rights of Access to MSS Facilities.

23.14.1 Installation of Facilities.

23.14.1.1 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.

23.14.1.2 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.

23.14.2 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.

23.14.3 Access During Emergencies.

Notwithstanding any provision in this Section 23, 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.

23.15 MSS System Unit

23.15.1 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 23.1.1, 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 23.1.1 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 5 and Section 2.3.2. In accordance with Section 5.1.3, the ISO will obtain control over the System Unit, not the individual Generating Unit, except for Regulation, to comply with Section 5.

23.15.2 Without limiting the generality of Section 23.15.1, a MSS Operator that owns or has an entitlement to a System Unit:

23.15.2.1 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;

23.15.2.2 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;

23.15.2.3 shall obtain ISO certification of the System Unit's Ancillary Service capabilities in accordance with Section 2.5.6 and 2.5.24 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;

23.15.2.4 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

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

23.15.3 Subject to Section 23.15.5, 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.

23.15.5 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 5.1.3 or, pursuant to Section 5.6, to a System Emergency.

23.16 MSS Settlements

23.16.1 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.

23.16.2 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 23.16.2 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 23.16.2, 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 2.3.5.1.8 for the calendar year for which the demonstration is made.

23.16.3 If the ISO is compensating Generating Units for emissions and start-up costs and if MSS Operator charges the ISO for the emissions and start-up 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 and start-up 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.

23.16.4 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.

24. [NOT USED]

25. [NOT USED]

26. TEMPORARY CHANGES TO ANCILLARY SERVICES PENALTIES

26.1 Application and Termination

The temporary change, respecting Ancillary Services penalties, set out in Section 26.2 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.caiso.com, or such other Internet address as the ISO may publish from time to time, specifying the date on which this Section 26 shall cease to apply, which date shall be not less than seven (7) days after the Notice of Full-Scale Operations is issued.

26.2 For so long as this Section 26.2 remains in effect, Scheduling Coordinators shall not be liable for the penalties specified in Section 2.5.26 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.

27. TEMPORARY RULE LIMITING ADJUSTMENT BIDS APPLICABLE TO DISPATCHABLE LOADS AND EXPORTS

27.1 Application and Termination

The temporary change limiting Adjustment Bids for Dispatchable Loads and exports set out in Section 27.2 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 27 shall cease to apply, which date shall not be less than seven (7) days after the Notice of Full-Scale Operations is posted.

27.2 For so long as this Section 27.2 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.

28. RULES LIMITING CERTAIN ENERGY AND ANCILLARY SERVICE BIDS

28.1 Damage Control Bid Cap

28.1 Notwithstanding any other provision of this ISO Tariff, Damage Control Bid Cap provisions of Section 28.1.2 and 28.1.3 shall apply to the ISO's Energy and Ancillary Service capacity markets.

28.1.2 **Maximum Bid Level.** The maximum bid level shall be $250/MWh. Market Participants may submit bids above $250/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.

28.1.3 Negative Decremental Energy Bids

Negative decremental Energy bids into the ISO Markets less than -$30/MWh (minus thirty dollars per MWh) shall not be eligible to set any Market Clearing Price and, if Dispatched, shall be paid as bid. If the ISO Dispatches a bid below -$30/MWh, the supplier must submit a detailed breakdown of the component costs justifying the bid to the ISO and to the Federal Energy Regulatory Commission no later than seven (7) days after the end of the month in which the bid was submitted. The ISO will treat such information as confidential and will apply the procedures in Section 20.3.4 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.

29. [NOT USED]

30. YEAR 2000 COMPLIANCE

30.1 Y2K Compliance

"Y2K Compliance" or "Y2K Compliant" means hardware, software, firmware, or other systems or processes (hereafter "systems and processes") that correctly manage, calculate, compare and sequence date data from, into and between the 20th and 21st centuries, including leap year calculations, without human intervention. Y2K Compliant systems and processes must utilize input and output date formats that are compatible with the ISO's systems and processes, must conform to the International Organization for Standardization ISO 8601:1988 standards for representation of dates and must not cause incorrect date calculations.

30.2 Responsibility for Y2K Compliance

It is the sole responsibility of each Market Participant or other entity that interfaces with the ISO's systems and processes to ensure that the entity's interfacing systems or processes are Y2K Compliant. The ISO will provide joint Y2K test opportunities to ensure interoperability between the ISO systems and external systems that interface with the ISO (e.g., Scheduling Coordinators, and other entities). This proactive test program is an opportunity to minimize the possibilities of transmitting Y2K related erroneous data to the ISO. Participation in this testing program is voluntary, and not a requirement.

30.3 Disconnection of Non-Y2K Compliant Systems and Processes

In order to protect and maintain the integrity of the ISO's systems and processes, the ISO shall have the authority to immediately disconnect the systems or processes of any Scheduling Coordinator or other entity that is believed by the ISO to be passing Y2K related erroneous data; i.e., data from systems and processes that do not meet the Section 30.1 standards for Y2K Compliance. The ISO will immediately notify the disconnected Scheduling Coordinator or other entity of the reason for the action taken by the ISO. The ISO shall permit such Scheduling Coordinator or other entity to reestablish interfaces with the ISO after receiving and approving documented test results showing that the disconnected systems or processes are Y2K Compliant and would not otherwise adversely affect the ISO's systems and processes. The ISO will review and approve or reject documented test results within two (2) Business Days of their receipt. The ISO will reconnect the entity within one (1) Business Day of the ISO's approval.

ISO TARIFF APPENDIX A

Master Definitions Supplement

Access Charge	A charge paid by all UDCs and MSS Operators with Gross Load in a PTO Service Territory, as set forth in Section 7.1. The Access Charge includes the High Voltage Access Charge, the Transition Charge and the Low Voltage Access Charge. The Access Charge will recover the Participating TO's Transmission Revenue Requirement in accordance with Appendix F, Schedule 3.
Active Zone	The Zones so identified in Appendix I to the ISO Tariff.
Adjustment Bid	A bid in the form of a curve defined by (i) the minimum MW output to which a Scheduling Coordinator will permit a resource (Generating Unit or Dispatchable Load) included in its Schedule or, in the case of an inter-Scheduling Coordinator trade, included in its Schedule or the Schedule of another Scheduling Coordinator, to be redispatched by the ISO; (ii) the maximum MW output to which a Scheduling Coordinator will permit the resource included in its Schedule or, in the case of an inter-Scheduling Coordinator trade, included in its Schedule or the Schedule of another Scheduling Coordinator, to be redispatched by the ISO; (iii) up to a specified number of MW values in between; (iv) a preferred MW operating point; and (v) for the ranges between each of the MW values greater than the preferred operating point, corresponding prices (in $/MWh) for

	which the Scheduling Coordinator is willing to increase the output of the resource and sell Energy from that resource to the ISO (or, in the case of a Dispatchable Load, decrease the Demand); and (vi) for the ranges between each of the MW values less than the preferred operating point, corresponding prices (in $/MWh) for which the Scheduling Coordinator is willing to decrease the output of the resource and purchase Energy from the ISO at the resource's location (or, in the case of a Dispatchable Load, increase the Demand). This data for an Adjustment Bid must result in a monotonically increasing curve.
Administrative Price	The price set by the ISO in place of a Market Clearing Price when, by reason of a System Emergency, the ISO determines that it no longer has the ability to maintain reliable operation of the ISO Controlled Grid relying solely on the economic Dispatch of Generation. This price will remain in effect until the ISO considers that the System Emergency has been contained and corrected.
Affiliate	An entity, company or person that directly, or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with the subject entity, company, or person.
AGC (Automatic Generation Control)	Generation equipment that automatically responds to signals from the ISO's EMS control in real time to control the power output of electric generators within a prescribed area in response to a change in system frequency, tie line loading, or the relation of these to each other, so as to maintain the target system frequency and/or the established interchange with other areas within the predetermined limits.

Alert Notice	A Notice issued by the ISO when the operating requirements of the ISO Controlled Grid are marginal because of Demand exceeding forecast, loss of major Generation, or loss of transmission capacity that has curtailed imports into the ISO Control Area, or if the Hour-Ahead Market is short on scheduled Energy and Ancillary Services for the ISO Control Area.
Ancillary Services	Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve, Voltage Support and Black Start together with such other interconnected operation services as the ISO may develop in cooperation with Market Participants to support the transmission of Energy from Generation resources to Loads while maintaining reliable operation of the ISO Controlled Grid in accordance with Good Utility Practice.
Ancillary Service Provider	A Participating Generator or Participating Load who is eligible to provide an Ancillary Serviced.

Applicable Reliability Criteria	The reliability standards established by NERC, WECC, and Local Reliability Criteria as amended from time to time, including any requirements of the NRC.
Applicants	Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company and any others as applicable.

Approved Credit Rating

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

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

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

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

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

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

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

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

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

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

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

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

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

Available Transfer Capacity For a given transmission path, the capacity rating in MW of the path established consistent with ISO and WECC transmission capacity rating guidelines, less any reserved uses applicable to the path.

Balanced Schedule A Schedule shall be deemed balanced when Generation, adjusted for Transmission Losses equals forecast Demand with respect to all entities for which a Scheduling Coordinator schedules.

Balancing Account An account set up to allow periodic balancing of financial transactions that, in the normal course of business, do not result in a zero balance of cash inflows and outflows.

BEEP Interval The time period, which may range between five (5) and thirty (30) minutes, over which the ISO's BEEP Software measures deviations in Generation and Demand, and selects Ancillary Service and Supplemental Energy resources to provide balancing Energy in response to such deviations. As of the ISO Operations Date, the BEEP Interval shall be ten (10) 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 BEEP Interval within the range of five (5) to thirty (30) minutes.

BEEP Interval Ex Post Prices	The prices charged to or paid by Scheduling Coordinators for Imbalance Energy in each Zone in each BEEP Interval.
BEEP Software	The balancing energy and ex post pricing software which is used by the ISO to determine which Ancillary Service and Supplemental Energy resources to Dispatch and to calculate the Ex Post Prices.
Black Start	The procedure by which a Generating Unit self-starts without an external source of electricity thereby restoring power to the ISO Controlled Grid following system or local area blackouts.
Black Start Generator	A Participating Generator in its capacity as party to an Interim Black Start Agreement with the ISO for the provision of Black Start services, but shall exclude Participating Generators in their capacity as providers of Black Start services under their Reliability Must-Run Contracts.
Bulk Supply Point	A UDC metering point.
Business Day	A day on which banks are open to conduct general banking business in California.
C.F.R.	Code of Federal Regulations.
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.

Completed Application Date	For purposes of Section 5.7, the date on which a New Facility Operator submits an Interconnection Application to the ISO that satisfies the requirements of the ISO Tariff and 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.
Congestion	A condition that occurs when there is insufficient Available Transfer Capacity to implement all Preferred Schedules simultaneously or, in real time, to serve all Generation and Demand. "Congested" shall be construed accordingly.
Congestion Management	The alleviation of Congestion in accordance with Applicable ISO Protocols and Good Utility Practice.
Congestion Management Charge	The component of the Grid Management Charge that provides for the recovery of the ISO's costs of operating the Congestion Management process including, but not limited to, the management and operation of Inter-Zonal Congestion markets, Adjustment Bids, taking Firm Transmission Rights and Existing Contracts into account, and determining the price for mitigating Congestion for flows on Congested paths. The formula for determining the Congestion Management Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

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

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

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

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

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

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

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

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

Core Reliability Services Charge The 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 Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

CPUC The California Public Utilities Commission, or its successor.

Critical Protective System	Facilities and sites with protective relay systems and Remedial Action Schemes that the ISO determines may have a direct impact on the ability of the ISO to maintain system security and over which the ISO exercises Operational Control.
CTC (Competition Transition Charge)	A non-bypassable charge that is the mechanism that the California Legislature and the CPUC mandated to permit recovery of costs stranded as a result of the shift to the new market structure.
Curtailable Demand	Demand from a Participating Load that can be curtailed at the direction of the ISO in the real-time Dispatch of the ISO Controlled Grid. Scheduling Coordinators with Curtailable Demand may offer it to the ISO to meet Non-Spinning Reserve or Replacement Reserve requirements.
Data Adequacy Requirement	Any applicable minimum data requirements of the state agency responsible for generation siting or of any Local Regulatory Authority.
Day-Ahead	Relating to a Day-Ahead Market or Day-Ahead Schedule.
Day-Ahead Market	The forward market for Energy and Ancillary Services to be supplied during the Settlement Periods of a particular Trading Day that is conducted by the ISO, the PX, and other Scheduling Coordinators and which closes with the ISO's acceptance of the Final Day-Ahead Schedule.
Day-Ahead Schedule	A Schedule prepared by a Scheduling Coordinator or the ISO before the beginning of a Trading Day indicating the levels of Generation and Demand scheduled for each Settlement Period of that Trading Day.
Default GMM	Pre calculated GMM based on historical Load and interchange levels.

Delivery Point	The point where a transaction between Scheduling Coordinators is deemed to take place. It can be either the Generation input point, a Demand Take-Out Point, or a transmission bus at some intermediate location.
Delivery Upgrade	The transmission facilities, other than Direct Assignment Facilities and Reliability Upgrades, necessary to relieve Constraints on the ISO Controlled Grid and to ensure the delivery of energy from a New Facility to Load.
Demand	The rate at which Energy is delivered to Loads and Scheduling Points by Generation, transmission or distribution facilities. It is the product of voltage and the in-phase component of alternating current measured in units of watts or standard multiples thereof, e.g., 1,000W=1kW, 1,000kW=1MW, etc.
Demand Forecast	An estimate of Demand over a designated period of time.

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

Direct Assignment Facility	The transmission facilities necessary to physically and electrically interconnect a New Facility Operator to the ISO Controlled Grid at the point of Interconnection.
Dispatch	The operating control of an integrated electric system to: i) assign specific Generating Units and other sources of supply to effect the supply to meet the relevant area Demand taken as Load rises or falls; ii) control operations and maintenance of high voltage lines, substations, and equipment, including administration of safety procedures; iii) operate interconnections; iv) manage Energy transactions with other interconnected Control Areas; and v) curtail Demand.
Dispatch Instruction	An instruction by the ISO to a resource for increasing or decreasing its energy supply or demand from the Hour-Ahead Schedule to a specified operating point.
Dispatch Operating Point	The expected operating point of a resource that has received a Dispatch Instruction. The resource is expected to operate at the Dispatch Operating Point after completing the Dispatch Instruction, taking into account any relevant ramp rate and time delays. Energy expected to be produced or consumed above or below the Final Hour-Ahead Schedule in response to a Dispatch Instruction constitutes Instructed Imbalance Energy. For resources that have not received a Dispatch Instruction, the Dispatch Operating Point defaults to the corresponding Final Hour-Ahead Schedule.
Dispatchable Load	Load which is the subject of an Adjustment Bid.

Distribution System	The distribution assets of an IOU or Local Publicly Owned Electric Utility.
EEP (Electrical Emergency Plan)	A plan to be developed by the ISO in consultation with UDCs to address situations when Energy reserve margins are forecast to be below established levels.
Effective Price	The price, applied to undelivered Instructed Imbalance Energy, calculated by dividing the absolute value of the total payment or charge for Instructed Imbalance Energy by the absolute value of the total Instructed Imbalance Energy, for the Settlement Period; provided that, if both the total payment or charge and quantity of Instructed Imbalance Energy for the Settlement Period are negative, the Effective Price shall be multiplied by -1.0 (minus one).

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

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

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

Energy	The electrical energy produced, flowing or supplied by generation, transmission or distribution facilities, being the integral with respect to time of the instantaneous power, measured in units of watt-hours or standard multiples thereof, e.g., 1,000 Wh=1kWh, 1,000 kWh=1MWh, etc.
Energy Bid	The price at or above which a Generator has agreed to produce the next increment of Energy.
Energy Transmission Services Net Energy Charge	The component of the Grid Management Charge that provides, in conjunction with the Energy Transmission Services Uninstructed Deviations Charge, for the recovery of the ISO's costs of providing reliability on a scalable basis, i.e., a function of the intensity of the use of the transmission system within the Control Area and the occurrence of system outages and disruptions. The formula for determining the Energy Transmission Services Net Energy Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.
Energy Transmission Services Uninstructed Deviations Charge	The component of the Grid Management Charge that provides, in conjunction with the Energy Transmission Services Net Energy Charge, for the recovery of the ISO's costs of providing reliability on a scalable basis, in particular for the costs associated with balancing transmission flows that result from uninstructed deviations. The formula for determining the Energy Transmission Services Uninstructed Deviations Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

Entitlements	The right of a Participating TO obtained through contract or other means to use another entity's transmission facilities for the transmission of Energy.
Environmental Dispatch	Dispatch designed to meet the requirements of air quality and other environmental legislation and environmental agencies having authority or jurisdiction over the ISO.
Ex Post GMM	GMM that is calculated utilizing the real-time Power Flow Model in accordance with Section 7.4.2.1.2.
Ex Post Price	The Hourly Ex Post Price or the BEEP Interval Ex Post Price.
Ex Post Transmission Loss	Transmission Loss that is calculated based on Ex Post GMM.

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

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

Final Hour-Ahead Schedule	The Hour-Ahead Schedule of Generation and Demand that has been approved by the ISO as feasible and consistent with all other Schedules based on the ISO's Hour-Ahead Congestion Management procedures.
Final Invoice	The invoice due from a RMR Owner to the ISO at termination of the RMR Contract.
Final Schedule	A Schedule developed by the ISO following receipt of a Revised Schedule from a Scheduling Coordinator.
Final Settlement Statement	The restatement or recalculation of the Preliminary Settlement Statement by the ISO following the issue of that Preliminary Settlement Statement.
Forced Outage	An Outage for which sufficient notice cannot be given to allow the Outage to be factored into the Day-Ahead Market or Hour-Ahead Market scheduling processes.
Forward Scheduling Charge	The component of the Grid Management Charge that provides for the recovery of the ISO's costs, including, but not limited to the costs of providing the ability to Scheduling Coordinators to forward schedule Energy and Ancillary Services and the cost of processing accepted Ancillary Service bids. For purposes of the Forward Scheduling Charge, a schedule is represented by each Final Hour-Ahead Schedule with a value other than 0 MW submitted to the scheduling infrastructure/scheduling

application system (import, export, Load, Generation, inter-Scheduling Coordinator trade, and Ancillary Services, including self-provided Ancillary Services) submitted to the ISO's scheduling infrastructure. The formula for determining the Forward Scheduling Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

FPA Parts II and III of the Federal Power Act, 16 U.S.C. § 824 et seq., as they may be amended from time to time.

FTR (Firm Transmission Right) A contractual right, subject to the terms and conditions of the ISO Tariff, that entitles the FTR Holder to receive, for each hour of the term of the FTR, a portion of the Usage Charges received by the ISO for transportation of energy from a specific originating Zone to a specific receiving Zone and, in the event of an uneconomic curtailment to manage Day-Ahead Congestion, to a Day-Ahead scheduling priority higher than that of a Schedule using Converted Rights capacity that does not have an FTR.

FTR Bidder	An entity that submits a bid in an FTR auction conducted by the ISO in accordance with Section 9.4 of the ISO Tariff.
FTR Holder	The owner of an FTR, as registered with the ISO.
FTR Market	A transmission path from an originating Zone to a contiguous receiving Zone for which FTRs are auctioned by the ISO in accordance with Section 9.4 of the ISO Tariff.
Full Marginal Loss Rate	A rate calculated by the ISO for each Generation and Scheduling Point location to determine the effect on total system Transmission Losses of injecting an increment of Generation at each such location to serve an equivalent incremental MW of Demand distributed proportionately throughout the ISO Control Area.
Generating 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 Faith Deposit	The deposit paid to the ISO by a New Facility Operator with submission of its Interconnection Application in accordance with Section 5.7.3.2, in an amount equal to $10,000, including any interest that accrues on the original amount, less any bank fees or other charges assessed on the escrow account. A New Facility Operator may satisfy its deposit obligation through any commercially available financial instrument determined to be satisfactory by the ISO.
Good Utility Practice	Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the

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

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

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

Gross Load For the purposes of calculating the transmission Access Charge, Gross Load is all Energy (adjusted for distribution losses) delivered for the supply of End-Use Customer Loads directly connected to the transmission facilities or directly connected to the Distribution System of a UDC or MSS Operator located in a PTO Service Territory. Gross Load shall exclude Load with respect to which the Wheeling Access Charge is payable and the portion of the Load of an individual retail customer of a UDC or MSS Operator that is served by a Generating Unit that: (a) is located on the customer's site or provides service to the customers site through arrangements as authorized by Section 218 of the California Public Utilities Code; (b) is a qualifying small power production facility or qualifying cogeneration facility, as those terms are defined in the FERC's regulations implementing Section 201 of the Public Utility Regulatory Policies Act of 1978; and

(c) secures Standby Service from a Participating TO under terms approved by a Local Regulatory Authority or FERC, as applicable, or can be curtailed concurrently with an outage of the Generating Unit serving the Load. In the case of a Local Publicly Owned Electric Utility that (a) is a Participating TO, (b) is in compliance with all metering requirements of Section 10 and the Metering Protocols of the ISO Tariff applicable to a utility that is an ISO Metered Entity, and (c) has not received a waiver of such metering requirements, Gross Load shall also exclude the portion of the Local Publicly Owned Electric Utility's Load that is served by a Generating Unit that (a) is directly connected to the Load through the Local Publicly Owned Electric Utility's Distribution System, (b) has certified and polled metering, and (c) is operated at greater than 50% capacity in the current month as measured by such a meter. Gross Load forecasts consistent with filed TRR will be provided by each Participating TO to the ISO.

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

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

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

High Voltage Wheeling Access Charge	The Wheeling Access Charge associated with the recovery of a Participating TO's High Voltage Transmission Revenue Requirements in accordance with Section 7.1.
Hour-Ahead	Relating to an Hour-Ahead Market or an Hour-Ahead Schedule.
Hour-Ahead Market	The forward market for Energy and Ancillary Services to be supplied during a particular Settlement Period that is conducted by the ISO and other Scheduling Coordinators which opens after the ISO's acceptance of the Final Day-Ahead Schedule for the Trading Day in which the Settlement Period falls and closes with the ISO's acceptance of the Final Hour-Ahead Schedule.
Hour-Ahead Schedule	A Schedule prepared by a Scheduling Coordinator or the ISO before the beginning of a Settlement Period indicating the changes to the levels of Generation and Demand scheduled for that Settlement Period from that shown in the Final Day-Ahead Schedule.

Hourly Ex Post Price	The prices charged or paid to Scheduling Coordinators Responsible for Participating Generators and Participating Buyers for Imbalance Energy in each Zone. The price will vary between Zones if Congestion is present. The Hourly Ex Post Price is the Energy-weighted average of the BEEP Interval Ex Post Prices in each Zone during each Settlement Period.
Hydro Spill Generation	Hydro-electric Generation in existence prior to the ISO Operations Date that: i) has no storage capacity and that, if backed down, would spill; ii) has exceeded its storage capacity and is spilling even though the generators are at full output, or iii) has inadequate storage capacity to prevent loss of hydro-electric Energy either immediately or during the forecast period, if hydro-electric Generation is reduced; iv) has increased regulated water output to avoid an impending spill.
Identification Code	An identification number assigned to each Scheduling Coordinator by the ISO.
Imbalance Energy	Imbalance Energy is Energy from Regulation, Spinning and Non-Spinning Reserves, or Replacement Reserve, or Energy from other Generating Units, System Units, System Resources, or Loads that are able to respond to the ISO's request for more or less Energy.
Inactive Zone	All Zones which the ISO Governing Board has determined do not have a workably competitive Generation market and as set out in Appendix I to the ISO Tariff.

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

Inter-Zonal Interface	The (i) group of transmission paths between two adjacent Zones of the ISO Controlled Grid, for which a physical, non-simultaneous transmission capacity rating (the rating of the interface) has been established or will be established prior to the use of the interface for Congestion Management; (ii) the group of transmission paths between an ISO Zone and an adjacent Scheduling Point, for which a physical, non-simultaneous transmission capacity rating (the rating of the interface) has been established or will be established prior to the use of the interface for Congestion Management; or (iii) the group of transmission paths between two adjacent Scheduling Points, where the group of paths has an established transfer capability and established transmission rights.
Interconnection	Transmission facilities, other than additions or replacements to existing facilities that: i) connect one system to another system where the facilities emerge from one and only one substation of the two systems and are functionally separate from the ISO Controlled Grid facilities such that the facilities are, or can be, operated and planned as a single facility; or ii) are identified as radial transmission lines pursuant to contract; or iii) produce Generation at a single point on the ISO Controlled Grid; provided that such interconnection does not include facilities that, if not owned by the Participating TO, would result in a reduction in the ISO’s Operational Control of the Participating TO’s portion of the ISO Controlled Grid.

Interconnecting PTO	For purposes of Section 5.7, the Participating TO that will supply the connection to the New Facility.
Interconnection Agreement	A contract between a party requesting interconnection and the Participating TO that owns the transmission facility with which the requesting party wishes to interconnect.
Interconnection Application	An application that requests interconnection of a New Facility to the ISO Controlled Grid and that meets the information requirements as specified by the ISO and posted on the ISO Home Page.
Interest	Interest shall be calculated in accordance with the methodology specified for interest on refunds in the regulations of FERC at 18 C.F.R. §35.19(a)(2)(iii) (1996). Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment, except as provided in SABP 6.10.5. When payments are made by mail, bills shall be considered as having been paid on the date of receipt.
Interruptible Imports	Energy sold by a Generator or resource located outside the ISO Controlled Grid which by contract can be interrupted or reduced at the discretion of the seller.
Intra-Zonal Congestion	Congestion within a Zone.
IOU	An investor owned electric utility.
ISO (Independent System Operator)	The California Independent System Operator Corporation, a state chartered, nonprofit corporation that controls the transmission facilities of all Participating TOs and dispatches certain Generating Units and Loads.
ISO Account	The ISO Clearing Account, the ISO Reserve Account or such other trust accounts as the ISO deems necessary or convenient for the purpose of efficiently implementing the funds transfer system under the ISO Tariff.

ISO ADR Committee The Committee appointed by the ISO ADR Committee pursuant to Article IV, Section 3 of the ISO bylaws to perform functions assigned to the ISO ADR Committee in the ADR process in Section 13 of the ISO Tariff.

ISO ADR Procedures	The procedures for resolution of disputes or differences set out in Section 13 of the ISO Tariff, as amended from time to time.
ISO Audit Committee	A Committee of the ISO Governing Board appointed pursuant to Article IV, Section 5 of the ISO bylaws to (1) review the ISO's annual independent audit (2) report to the ISO Governing Board on such audit, and (3) to monitor compliance with the ISO Code of Conduct.
ISO Authorized Inspector	A person authorized by the ISO to certify, test, inspect and audit meters and Metering Facilities (as that term is defined in the ISO Metering Protocol) in accordance with the procedures established by the ISO pursuant to the ISO Protocols on metering.
ISO Bank	The bank appointed by the ISO from time to time for the purposes of operating the Settlement process.
ISO Clearing Account	The account in the name of the ISO with the ISO Bank to which payments are required to be transferred for allocation to ISO Creditors in accordance with their respective entitlements.
ISO Code of Conduct	For employees, the code of conduct for officers, employees and substantially full-time consultants and contractors of the ISO as set out in exhibit A to the ISO bylaws; for Governors, the code of conduct for governors of the ISO as set out in exhibit B to the ISO bylaws.
ISO Control Area Balancing Function	The real-time Dispatch of Generation (and Curtailable Demand), directed by the ISO, to balance with actual Demand during the current operating hour to meet operating Reliability Criteria.
ISO Control Center	The Control Center established, pursuant to Section 2.3.1.1 of the ISO Tariff.

ISO Controlled Grid	The system of transmission lines and associated facilities of the Participating TOs that have been placed under the ISO's Operational Control.
ISO Creditor	A Scheduling Coordinator, Participating TO, or other Market Participant to which amounts are payable under the terms of the ISO Tariff.
ISO Debtor	A Scheduling Coordinator, Participating TO, or other Market Participant that is required to make a payment to the ISO under the ISO Tariff.
ISO Documents	The ISO Tariff, the ISO Protocols, ISO bylaws, and any agreement entered into between the ISO and a Scheduling Coordinator, a Participating TO or any other Market Participant pursuant to the ISO Tariff.
ISO Governing Board	The Board of Governors established to govern the affairs of the ISO.
ISO Home Page	The ISO internet home page at http://www.caiso.com/ or such other internet address as the ISO shall publish from time to time.
ISO Invoice	The invoices issued by the ISO to the Responsible Utilities or RMR Owners based on the Revised Estimated RMR Invoice and the Revised Adjusted RMR Invoice.

<u>ISO Market</u>	Any of the markets administered by the ISO under the ISO Tariff, including, without limitation, Imbalance Energy, Ancillary Services, and FTRs.
<u>ISO Memorandum Account</u>	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.
<u>ISO Metered Entity</u>	a) any one of the following entities that is directly connected to the ISO Controlled Grid: i. a Generator other than a Generator that sells all of its Energy (excluding any Energy consumed by auxiliary load equipment electrically connected to that Generator at the same point) and Ancillary Services to the UDC in whose Service Area it is located; ii. an Eligible Customer; or iii. an End-User other than an End-User that purchases all of its Energy from the UDC in whose Service Area it is located; and (b) any one of the following entities: i. a Participating Generator; ii. a Participating TO in relation to its Tie Point Meters with other TOs or Control Areas; iii. a Participating Load; iv. a Participating Intermittent Resource; or v. a utility that requests that UFE for its Service Area be calculated separately, in relation to its meters at points of connection of its Service Area with the systems of other

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

ISO Payments Calendar	A calendar published by the ISO showing the dates on which Settlement Statements will be published by the ISO and the Payment Dates by which invoices issued under the ISO Tariff must be paid.
ISO Protocols	The rules, protocols, procedures and standards attached to the ISO Tariff as Appendix L, promulgated by the ISO (as amended from time to time) to be complied with by the ISO Scheduling Coordinators, Participating TOs and all other Market Participants in relation to the operation of the ISO Controlled Grid and the participation in the markets for Energy and Ancillary Services in accordance with the ISO Tariff.
ISO Register	The register of all the transmission lines, associated facilities and other necessary components that are at the relevant time being subject to the ISO's Operational Control.
ISO Reserve Account	The account established for the purpose of holding cash deposits which may be used in or towards clearing the ISO Clearing Account.
ISO Security Amount	The level of security provided in accordance with Section 2.2.3.2 of the ISO Tariff by an SC Applicant who does not have an Approved Credit Rating. The ISO Security Amount may be separated into two components: (i) the level of security required to secure payment of the Grid Management Charge; and (ii) the level of security required to secure payment of all charges other than the Grid Management Charge.
ISO Tariff	The California Independent System Operator Corporation Operating Agreement and Tariff, dated March 31, 1997, as it may be modified from time to time.

ISP (Internet Service Provider)	An independent network service organization engaged by the ISO to establish, implement and operate WEnet.
Load	An end-use device of an End-Use Customer that consumes power. Load should not be confused with Demand, which is the measure of power that a Load receives or requires.
Load Shedding	The systematic reduction of system Demand by temporarily decreasing the supply of Energy to Loads in response to transmission system or area capacity shortages, system instability, or voltage control considerations.
Local Furnishing Bond	Tax-exempt bonds utilized to finance facilities for the local furnishing of electric energy, as described in section 142(f) of the Internal Revenue Code, 26 U.S.C. § 142(f).
Local Furnishing Participating TO	Any Tax-Exempt Participating TO that owns facilities financed by Local Furnishing Bonds.
Local Publicly Owned Electric Utilities	A municipality or municipal corporation operating as a public utility furnishing electric service, a municipal utility district furnishing electric service, a public utility district furnishing electric services, an irrigation district furnishing electric services, a state agency or subdivision furnishing electric services, a rural cooperative furnishing electric services, or a joint powers authority that includes one or more of these agencies and that owns Generation or transmission facilities, or furnishes electric services over its own or its members' electric Distribution System.

Local Regulatory Authority	The state or local governmental authority responsible for the regulation or oversight of a utility.
Local Reliability Criteria	Reliability Criteria established at the ISO Operations Date, unique to the transmission systems of each of the Participating TOs.
Location Code	The code assigned by the ISO to Generation input points, and Demand Take-Out Points from the ISO Controlled Grid, and transaction points from trades between Scheduling Coordinators. This will be the information used by the ISO Controlled Grid, and transaction points for trades between Scheduling Coordinators. This will be the information used by the ISO to determine the location of the input, output, and trade points of Energy Schedules. Each Generation input and Demand Take-Out Point will have a designated Location Code identification for use in submitting Energy and Ancillary Service bids and Schedules.
Loop Flow	Energy flow over a transmission system caused by parties external to that system.
Loss Scale Factor	The ratio of expected Transmission Losses to the total Transmission Losses which would be collected if Full Marginal Loss Rates were utilized.
Low Voltage Access Charge	The Access Charge applicable under Section 7.1 to recover the Low Voltage Transmission Revenue Requirement of a Participating TO.
Low Voltage Transmission Facility	A transmission facility owned by a Participating TO or to which a Participating TO has an Entitlement that is represented by a Converted Right, which is not a High Voltage Transmission Facility, that is under the ISO Operational Control.

Low Voltage Transmission Revenue Requirement	The portion of a Participating TO's TRR associated with and allocable to the Participating TO's Low Voltage Transmission Facilities and Converted Rights associated with Low Voltage Transmission Facilities that are under the ISO Operational Control.
Low Voltage Wheeling Access Charge	The Wheeling Access Charge associated with the recovery of a Participating TO's Low Voltage Transmission Revenue Requirement in accordance with Section 7.1.
Maintenance Outage	A period of time during which an Operator (i) takes its transmission facilities out of service for the purposes of carrying out routine planned maintenance, or for the purposes of new construction work or for work on de-energized and live transmission facilities (e.g., relay maintenance or insulator washing) and associated equipment; or (ii) limits the capability of or takes its Generating Unit or System Unit out of service for the purposes of carrying out routine planned maintenance, or for the purposes of new construction work.

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

Market Participant	An entity, including a Scheduling Coordinator, who participates in the Energy marketplace through the buying, selling, transmission, or distribution of Energy or Ancillary Services into, out of, or through the ISO Controlled Grid.
Market Usage Charge	The component of the Grid Management Charge that provides for the recovery of the ISO's costs, including, but not limited to the costs for processing Supplemental Energy and Ancillary Service bids, maintaining the Open Access Same-Time Information System, monitoring market performance, ensuring generator compliance with market protocols, and determining Market Clearing Prices. The formula for determining the Market Usage Charge is set forth in Appendix F, Schedule 1, Part A of this Tariff.

Master File A file containing information regarding Generating Units, Loads and other resources.

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 Energy Transmission Services Net Energy Charge component of the Grid Management Charge, Metered Control Area Load is: (a) all metered Demand for Energy of Scheduling Coordinators for the supply of Loads in the ISO's Control Area, plus (b) all Energy for exports by Scheduling Coordinators from the ISO Control Area; less (c) Energy associated with the Load of a retail customer of a Scheduling Coordinator, UDC, or MSS that is served by a Generating Unit that: (i) is located on the same site as the customer's Load or provides service to the customer's Load through arrangements as authorized by Section 218 of the California Public Utilities Code; (ii) is a qualifying small power production facility or qualifying cogeneration facility, as those terms are defined in FERC's regulations implementing Section 201 of the Public Utility Regulatory Policies Act of 1978; and (iii) the customer secures Standby Service from a Participating TO under terms approved by a Local Regulatory Authority or FERC, as applicable, or the customer's Load can be curtailed concurrently with an outage of the Generating Unit.

Metered Quantities	For each Direct Access End-User, the actual metered amount of MWh and MW; for each Participating Generator the actual metered amounts of MWh, MW, MVAr and MVArh.
Minimum Load Costs	The costs a Generating Unit incurs operating at minimum load.
Monthly Peak Load	The maximum hourly Demand on a Participating TO's transmission system for a calendar month, multiplied by the Operating Reserve Multiplier.
MSS (Metered Subsystem)	A geographically contiguous system located within a single Zone which has been operating as an electric utility for a number of years prior to the ISO Operations Date as a municipal utility, water district, irrigation district, State agency or Federal power administration subsumed within the ISO Control Area and encompassed by ISO certified revenue quality meters at each interface point with the ISO Controlled Grid and ISO certified revenue quality meters on all Generating Units or, if aggregated, each individual resource and Participating Load internal to the system, which is operated in accordance with a MSS Agreement described in Section 23.1.
MSS Operator	An entity that owns an MSS and has executed a MSS Agreement.

Municipal Tax Exempt Debt An obligation the interest on which is excluded from gross income for federal tax purposes pursuant to Section 103(a) of the Internal Revenue Code of 1986 or the corresponding provisions of prior law without regard to the identity of the holder thereof. Municipal Tax Exempt Debt does not include Local Furnishing Bonds.

Must-Offer Generator All entities defined in Section 5.11.1 of the ISO Tariff

Native Load Load required to be served by a utility within its Service Area pursuant to applicable law, franchise, or statute.

NERC The North American Electric Reliability Council or its successor.

Net FTR Revenue The sum of: 1) the revenue received by the New Participating TO from the sale, auction, or other transfer of the FTRs provided to it pursuant to Section 9.4.3 FTR, or any substantively identical successor provision of the ISO Tariff; and 2) for each hour: a) the Usage Charge revenue received by the New Participating To associated with its Section 9.4.3 FTRs; minus b) Usage Charges that are: i) incurred by the Scheduling Coordinator for the New Participating TO under ISO Tariff Section 7.3.1.4, ii) associated with the New Participating TO's Section 9.4.3 FTRs, and iii) incurred by the New Participating TO for its energy transactions but not incurred as a result of the use of the transmission by a third-party and minus c) the charges paid by the New Participating TO pursuant to Section 7.3.1.7, to the extent such charges are incurred by the Scheduling Coordinator of the New Participating TO on Congested Inter-Zonal Interfaces that are associated with the Section 9.4.3 FTRs provided to the New Participating TO. The component of New FTR Revenue represented by item 2) immediately above shall not be less than zero for any hour.

Net Negative Uninstructed Deviation The real-time change in Generation or Demand associated with underscheduled Load (i.e., Load that appears unscheduled in real time) and overscheduled Generation (i.e., Generation that is scheduled in forward markets and does not appear in real time). Deviations are netted for each BEEP Interval, apply to a Scheduling Coordinator's entire portfolio, and include Load, Generation, imports and exports.

New Facility	A planned or Existing Generating Unit that requests, pursuant to Section 5.7 of the ISO Tariff, to interconnect or modify its interconnection to the ISO Controlled Grid.
New Facility License	A license issued by a federal, state or Local Regulatory Authority that enables an entity to build and operate a Generating Unit.
New Facility Operator	The owner of a planned New Facility, or its designee.
New High Voltage Facility	A High Voltage Transmission Facility of a Participating TO that is placed in service after the beginning of the transition period described in Section 4 of Schedule 3 of Appendix F, or a capital addition made and placed in service after the beginning of the transition period described in Section 4.2 of Schedule 3 of Appendix F to an Existing High Voltage Facility.
New Participating TO	A Participating TO that is not an Original Participating TO.
Nomogram	A set of operating or scheduling rules which are used to ensure that simultaneous operating limits are respected, in order to meet NERC and WECC operating criteria.

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

Operating Reserve	The combination of Spinning and Non-Spinning Reserve required to meet WECC and NERC requirements for reliable operation of the ISO Control Area.
Operational Control	The rights of the ISO under the Transmission Control Agreement and the ISO Tariff to direct Participating TOs how to operate their transmission lines and facilities and other electric plant affecting the reliability of those lines and facilities for the purpose of affording comparable non-discriminatory transmission access and meeting Applicable Reliability Criteria.
Operator	The operator of facilities that comprise the ISO Controlled Grid or a Participating Generator.
OPF (Optimal Power Flow)	A computer optimization program which uses a set of control variables (which may include active power and/or reactive power controls) to determine a steady-state operating condition for the transmission grid for which a set of system operating Constraints (which may include active power and/or reactive power constraints) are satisfied and an objective function (e.g. total cost or shift of schedules) is minimized.
Order No. 888	The final rule issued by FERC entitled "Promoting Wholesale Competition through Open Access Non- discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities," 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs., Regulations Preambles [1991-1996] ¶ 31,036 (1996), Order on Rehearing, Order No. 888-A, 78 FERC ¶ 61,220 (1997), as it may be amended from time to time.

Order No. 889	The final rule issued by FERC entitled "Open Access Same-Time Information System (formerly Real Time Information Networks) and Standards of Conduct," 61 Fed. Reg. 21,737 (May 10, 1996), FERC Stats. & Regs., Regulations Preambles [1991-1996] ¶ 31,035 (1996), Order on Rehearing, Order No. 889-A, 78 FERC ¶ 61,221 (1997), as it may be amended from time to time.
Original Participating TO	A Participating TO that was a Participating TO as of January 1, 2000.
Outage	Disconnection or separation, planned or forced, of one or more elements of an electric system.
Overgeneration	A condition that occurs when total Generation exceeds total Demand in the ISO Control Area.

Participating Buyer	A Direct Access End-User or a wholesale buyer of Energy or Ancillary Services through Scheduling Coordinators.
Participating Intermittent Resource	One or more Eligible Intermittent Resources that meets the requirements of the technical standards for Participating Intermittent Resources adopted by the ISO and published on the ISO Home Page.
Participating Load	An entity providing Curtailable Demand, which has undertaken in writing to comply with all applicable provisions of the ISO Tariff, as they may be amended from time to time.
Participating Seller or Participating Generator	A Generator or other seller of Energy or Ancillary Services through a Scheduling Coordinator over the ISO Controlled Grid from a Generating Unit with a rated capacity of 1 MW or greater, or from a Generating Unit providing Ancillary Services and/or submitting Supplemental Energy bids through an aggregation arrangement approved by the ISO, which has undertaken to be bound by the terms of the ISO Tariff, in the case of a Generator through a Participating Generator Agreement.

Participating TO	A party to the TCA whose application under Section 2.2 of the TCA has been accepted and who has placed its transmission assets and Entitlements under the ISO's Operational Control in accordance with the TCA. A Participating TO may be an Original Participating TO or a New Participating TO.
Payment Date	The date by which invoiced amounts are to be paid under the terms of the ISO Tariff.
PBR (Performance-Based Ratemaking)	Regulated rates based in whole or in part on the achievement of specified performance objectives.
Physical Scheduling Plant	A group of two or more related Generating Units, each of which is individually capable of producing Energy, but which either by physical necessity or operational design must be operated as if they were a single Generating Unit and any Generating Unit or Units containing related multiple generating components which meet one or more of the following criteria: i) multiple generating components are related by a common flow of fuel which cannot be interrupted without a substantial loss of efficiency of the combined output of all components; ii) the Energy production from one component necessarily causes Energy production from other components; iii) the operational arrangement of related multiple generating components determines the overall physical efficiency of the combined output of all components; iv) the level of coordination required to schedule individual generating components would cause the ISO to incur scheduling costs far in excess of the benefits of having scheduled such individual components separately; or

v) metered output is available only for the combined output of related multiple generating components and separate generating component metering is either impractical or economically inefficient.

Planning Procedures	Procedures governing the planning, expansion and reliable interconnection to the ISO Controlled Grid that the ISO may, from time to time, develop.
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.
Power Flow Model	The computer software used by the ISO to model the voltages, power injections and power flows on the ISO Controlled Grid and determine the expected Transmission Losses and Generation Meter Multipliers.
Preferred Day-Ahead Schedule	A Scheduling Coordinator's Preferred Schedule for the ISO Day-Ahead scheduling process.
Preferred Hour-Ahead Schedule	A Scheduling Coordinator's Preferred Schedule for the ISO Hour-Ahead scheduling process.
Preferred Schedule	The initial Schedule produced by a Scheduling Coordinator that represents its preferred mix of Generation to meet its Demand. For each Generator, the Schedule will include the quantity of output, details of any Adjustment Bids, and the location of the Generator. For each Load, the Schedule will include the quantity of consumption, details of any Adjustment Bids, and the location of the Load. The Schedule will also specify quantities and location of trades between the Scheduling Coordinator and all other Scheduling Coordinators. The

Preferred Schedule will be balanced with respect to Generation, Transmission Losses, Load and trades between Scheduling Coordinators.

Preliminary Settlement Statement	The initial statement issued by the ISO of the calculation of the Settlements and allocation of the charges in respect of all Settlement Periods covered by the period to which it relates.
Project Sponsor	A Market Participant or group of Market Participants or a Participating TO that proposes the construction of a transmission addition or upgrade in accordance with Section 3.2 of the ISO Tariff.
Proxy Price	The value determined for each gas-fired Generating Unit owned or controlled by a Must-Offer Generator in accordance with Section 2.5.23.3.4.
PTO Service Territory	The area in which an IOU, a Local Public Owned Electric Utility, or federal power marketing administration that has turned over its transmission facilities and/or Entitlements to ISO Operational Control is obligated to provided electric service to Load. A PTO Service Territory may be comprised of the Service Areas of more than one Local Publicly 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.

Ramping	Changing the loading level of a Generating Unit in a constant manner over a fixed time (e.g., ramping up or ramping down). Such changes may be directed by a computer or manual control.
RAS (Remedial Action Schemes)	Protective systems that typically utilize a combination of conventional protective relays, computer-based processors, and telecommunications to accomplish rapid, automated response to unplanned power system events. Also, details of RAS logic and any special requirements for arming of RAS schemes, or changes in RAS programming, that may be required.
Reactive Power Control	Generation or other equipment needed to maintain acceptable voltage levels on the ISO Controlled Grid and to meet reactive capacity requirements at points of interconnection on the ISO Controlled Grid.
Real Time Market	The competitive generation market controlled and coordinated by the ISO for arranging real-time Imbalance Energy.
Redispatch	The readjustment of scheduled Generation or Demand side management measures, to relieve Congestion or manage Energy imbalances.
Registered Data	Those items of technical data and operating characteristics relating to Generation, transmission or distribution facilities which are identified to the owners of such facilities as being information, supplied in accordance with ISO Protocols, to assist the ISO to maintain reliability of the ISO Controlled Grid and to carry out its functions.

Regulation The service provided either by Generating Units certified by the ISO as equipped and capable of responding to the ISO's direct digital control signals, or by System Resources that have been certified by the ISO as capable of delivering such service to the ISO Control Area, in an upward and downward direction to match, on a real-time basis, Demand and resources, consistent with established NERC and WECC operating criteria.

Regulation is used to control the power output of electric generators within a prescribed area in response to a change in system frequency, tieline loading, or the relation of these to each other so as to maintain the target system frequency and/or the established interchange with other areas within the predetermined limits. Regulation includes both the increase of output by a Generating Unit or System Resource ("Regulation Up") and the decrease in output by a Generating Unit or System Resource ("Regulation Down"). Regulation Up and Regulation Down are distinct capacity products, with separately stated requirements and Market Clearing Prices in each Settlement Period.

Regulation Energy Payment Adjustment The additional value of regulating Energy.

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

Reliability Must-Run Contract (RMR Contract)	A Must-Run Service Agreement between the owner of an RMR Unit and the ISO.
Reliability Must-Run Generation (RMR Generation)	Generation that the ISO determines is required to be on line to meet Applicable Reliability Criteria requirements. This includes i) Generation constrained on line to meet NERC and WECC reliability criteria for interconnected systems operation; ii) Generation needed to meet Load demand in constrained areas; and iii) Generation needed to be operated to provide voltage or security support of the ISO or a local area.
Reliability Must-Run Unit (RMR Unit)	A Generating Unit which is the subject of a Reliability Must-Run Contract.
Reliability Services Costs	The costs associated with services provided by the ISO: 1) that are deemed by the ISO as necessary to maintain reliable electric service in the ISO Control Area; and 2) whose costs are billed by the ISO to the Participating TO pursuant to the ISO Tariff. Reliability Services Costs include costs charged by the ISO to a Participating TO associated with service provided under an RMR Contract (Section 5.2.8), local out-of-market dispatch calls (Section 11.2.4.2.1) and Minimum Load Costs associated with units committed under the must-offer obligation for local reliability requirements (Section 5.11.6.1.4)
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 WECC practice, the facilities necessary to mitigate any adverse impact a New Facility's interconnection may have on a path's WECC path rating.
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.

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

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 Area 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.
SCADA (Supervisory Control and Data Acquisition)	A computer system that allows an electric system operator to remotely monitor and control elements of an electric system.
SC Agreement	An agreement between a Scheduling Coordinator and the ISO whereby the Scheduling Coordinator agrees to comply with all ISO rules, protocols and instructions, as those rules, protocols and instructions may be amended from time to time.
SC Applicant	An applicant for certification by the ISO as a Scheduling Coordinator.

SC Application Form	The form specified by the ISO from time to time in which an SC Applicant must apply to the ISO for certification as a Scheduling Coordinator.
Scaled Marginal Loss Rate	A factor calculated by the ISO for a given Generator location for each hour by multiplying the Full Marginal Loss Rate for such Generator location by the Loss Scale Factor for the relevant hour.
Schedule	A statement of (i) Demand, including quantity, duration and Take-Out Points and (ii) Generation, including quantity, duration, location of Generating Unit, and Transmission Losses; and (iii) Ancillary Services which will be self-provided, (if any) submitted by a Scheduling Coordinator to the ISO. "Schedule" includes Preferred Schedules, Suggested Adjusted Schedules, Final Schedules and Revised Schedules.
Scheduled Maintenance	Maintenance on Participating Generators, TOs and UDC facilities scheduled more than twenty-four hours in advance.
Scheduling Coordinator	An entity certified by the ISO for the purposes of undertaking the functions specified in Section 2.2.6 of the ISO Tariff.
Scheduling Coordinator Metered Entity or SC Metered Entity	A Generator, Eligible Customer or End-User that is not an ISO Metered Entity.

Scheduling Point	A location at which the ISO Controlled Grid is connected, by a group of transmission paths for which a physical, non-simultaneous transmission capacity rating has been established for Congestion Management, to transmission facilities that are outside the ISO's Operational Control. A Scheduling Point typically is physically located at an "outside" boundary of the ISO Controlled Grid (e.g., at the point of interconnection between a Control Area utility and the ISO Controlled Grid). For most practical purposes, a Scheduling Point can be considered to be a Zone that is outside the ISO's Controlled Grid.
Security Monitoring	The real-time assessment of the ISO Controlled Grid that is conducted to ensure that the system is operating in a secure state, and in compliance with all Applicable Reliability Criteria.
Service Area	An area in which an IOU or a Local Publicly Owned Electric Utility is obligated to provide electric service to End-Use Customers.
Set Point	Scheduled operating level for each Generating Unit or other resource scheduled to run in the Hour-Ahead Schedule.

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

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

Severance Fee	The charge or periodic charge assessed to customers to recover the reasonable uneconomic portion of costs associated with Generation-related assets and obligations, nuclear decommissioning, and capitalized Energy efficiency investment programs approved prior to August 15, 1996 and as defined in the California Assembly Bill No. 1890 approved by the Governor on September 23, 1996.
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.
Standby Rate	A rate assessed a Standby Service Customer by the Participating TO that also provides retail electric service, as approved by the Local Regulatory Authority, or FERC, as applicable, for Standby Service which compensates the Participating TO, among other things, for costs of High Voltage Transmission Facilities.
Standby Service	Service provided by a Participating TO that also provides retail electric service, which allows a Standby Service Customer, among other things, access to High Voltage Transmission Facilities for the delivery of backup power on an instantaneous basis to ensure that Energy may be reliably delivered to the Standby Service Customer in the event of an outage of a Generating Unit serving the customer's Load.
Standby Service Customer	A retail End-Use Customer of a Participating TO that also provides retail electric service that receives Standby Service and pays a Standby Rate.

Standby Transmission Revenue	The transmission revenues, with respect to cost of both High Voltage Transmission Facilities and Low Voltage Transmission Facilities, collected directly from Standby Service Customers through charges for Standby Service.

Start-Up Cost Charge	The charge determined in accordance with Section 2.5.23.3.7.
Start-Up Cost Demand	The level of Demand specified in Section 2.5.23.3.7.3.
Start-Up Cost Invoice	The invoice submitted to the ISO in accordance with Section 2.5.23.3.7.6.
Start-Up Cost Trust Account	The trust account established in accordance with Section 2.5.23.3.7.2.
Start-Up Costs	The cost incurred by a particular Generating Unit from the time of first fire, the time of receipt of an ISO Dispatch instruction, or the time the unit was last synchornized to the grid, whichever is later, until the time the generating unit is synchronized or re-synchronized to the grid and producing Energy. 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.

Suggested Adjusted Schedule	The output of the ISO's initial Congestion Management for each Scheduling Coordinator for the Day-Ahead Market ("Suggested Adjusted Day-Ahead Schedule") or for the Hour-Ahead Market ("Suggested Adjusted Hour-Ahead Schedule"). These Schedules will reflect ISO suggested adjustments to each Scheduling Coordinator's Preferred Schedule to resolve Inter-Zonal Congestion on the ISO Controlled Grid, based on the Adjustment Bids submitted. These Schedules will be balanced with respect to Generation, Transmission Losses, Load, and trades between Scheduling Coordinators to resolve Inter-Zonal Congestion.
Supplemental Energy	Energy from Generating Units bound by a Participating Generator Agreement, Loads bound by a Participating Load Agreement, System Units, and System Resources which have uncommitted capacity following finalization of the Hour-Ahead Schedules and for which Scheduling Coordinators have submitted bids to the ISO at least half an hour before the commencement of the Settlement Period.
Supply	The rate at which Energy is delivered to the ISO Controlled Grid measured in units of watts or standard multiples thereof, e.g., 1,000W=1 KW; 1,000 KW = 1MW, etc.

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

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

Take-Out Point	The metering points at which a Scheduling Coordinator Metered Entity or ISO Metered Entity takes delivery of Energy.
Tax Exempt Debt	Municipal Tax Exempt Debt or Local Furnishing Bonds.
Tax Exempt Participating TO	A Participating TO that is the beneficiary of outstanding Tax Exempt Debt issued to finance any electric facilities, or rights associated therewith, which are part of an integrated system including transmission facilities the Operational Control of which is transferred to the ISO pursuant to the TCA.
TCA (Transmission Control Agreement)	The agreement between the ISO and Participating TOs establishing the terms and conditions under which TOs will become Participating TOs and how the ISO and each Participating TO will discharge their respective duties and responsibilities, as may be modified from time to time.
Tie Point Meter	A revenue meter, which is capable of providing Settlement Quality Meter Data, at a Scheduling Point or at a boundary between UDCs within the ISO Controlled Grid.
TO (Transmission Owner)	An entity owning transmission facilities or having firm contractual rights to use transmission facilities.
TO Tariff	A tariff setting out a Participating TO's rates and charges for transmission access to the ISO Controlled Grid and whose other terms and conditions are the same as those contained in the document referred to as the Transmission Owners Tariff approved by FERC as it may be amended from time to time.
Trading Day	The twenty-four hour period beginning at the start of the hour ending 0100 and ending at the end of the hour ending 2400 daily, except where there is a change to and from daylight savings time.

Transition Charge	The component of the Access Charge collected by the ISO with the High Voltage Access Charge in accordance with Section 5.7 of Appendix F, Schedule 3.
Transition Period	The period of time established by the California Legislature and CPUC to allow IOUs and Local Publicly Owned Electric Utilities an opportunity to recover Transition Costs or Severance Fees.
Transmission Losses	Energy that is lost as a natural part of the process of transmitting Energy from Generation to Load delivered at the ISO/UDC boundary or Control Area boundary.
Transmission Revenue Credit	For an Original Participating TO, the proceeds received from the ISO for Wheeling service, FTR auction revenue and Usage Charges, plus the shortfall or surplus resulting from any cost differences between Transmission Losses and Ancillary Service requirements associated with Existing Rights and the ISO's rules and protocols. For a New Participating TO during the 10-year transition period described in Section 4 of Schedule 3 of Appendix F, the proceeds received from the ISO for Wheeling service and Net FTR Revenue, plus the shortfall or surplus resulting from any cost differences between Transmission Losses and Ancillary Service requirements associated with Existing Rights and the ISO's rules and protocols. After the 10-year transition period, the New Participating TO Transmission

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

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.
Trustee	The trustee of the California Independent System Operator trust established by order of the California Public Utilities Commission on August 2, 1996 Decision No. 96-08-038 relating to the Ex Parte Interim Approval of a Loan Guarantee and Trust Mechanism to Fund the Development of an Independent System Operator (ISO) and a Power Exchange (PX) pursuant to Decision 95-12-063 as modified.
UDC (Utility Distribution Company)	An entity that owns a Distribution System for the delivery of Energy to and from the ISO Controlled Grid, and that provides regulated retail electric service to Eligible Customers, as well as regulated procurement service to those End-Use Customers who are not yet eligible for direct access, or who choose not to arrange services through another retailer.

Unaccounted for Energy (UFE)	UFE is the difference in Energy, for each utility Service Area and Settlement Period, between the net Energy delivered into the utility Service Area, adjusted for utility Service Area Transmission Losses (calculated in accordance with Section 7.4.2), and the total metered Demand within the utility Service Area adjusted for distribution losses using Distribution System loss factors approved by the Local Regulatory Authority. This difference is attributable to meter measurement errors, power flow modeling errors, energy theft, statistical Load profile errors, and distribution loss deviations.
Uncontrollable Force	Any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm, flood, earthquake, explosion, any curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities or any other cause beyond the reasonable control of the ISO or Market Participant which could not be avoided through the exercise of Good Utility Practice.
Uninstructed Imbalance Energy	The real-time change in Generation or Demand other than that instructed by the ISO or which the ISO Tariff provides will be paid at the price for Uninstructed Imbalance Energy.
Unit Commitment	The process of determining which Generating Units will be committed (started) to meet Demand and provide Ancillary Services in the near future (e.g., the next Trading Day).
Usage Charge	The amount of money, per 1 kW of scheduled flow, that the ISO charges a Scheduling Coordinator for use of a specific Congested Inter-Zonal Interface during a given hour.

Voltage Limits For all substation busses, the normal and post-contingency Voltage Limits (kV). The bandwidth for normal Voltage Limits must fall within the bandwidth of the post-contingency Voltage Limits. Special voltage limitations for abnormal operating conditions such as heavy or light Demand may be specified.

Voltage Support Services provided by Generating Units or other equipment such as shunt capacitors, static var compensators, or synchronous condensers that are required to maintain established grid voltage criteria. This service is required under normal or System Emergency conditions.

Waiver Denial Period The period determined in accordance with Section 5.11.6.

Warning Notice A Notice issued by the ISO when the operating requirements for the ISO Controlled Grid are not met in the Hour-Ahead Market, or the quantity of Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve and Supplemental Energy available to the ISO does not satisfy the Applicable Reliability Criteria.

WEnet (Western Energy Network) An electronic network that facilitates communications and data exchange among the ISO, Market Participants and the public in relation to the status and operation of the ISO Controlled Grid.

Wheeling Wheeling Out or Wheeling Through.

Wheeling Access Charge The charge assessed by the ISO that is paid by a Scheduling Coordinator for Wheeling in accordance with Section 7.1. Wheeling Access Charges shall not apply for Wheeling under a bundled non-economy Energy coordination agreement of a Participating TO executed prior to July 9, 1996. The Wheeling Access Charge may consist of a High Voltage Wheeling Access Charge and a Low Voltage Wheeling Access Charge.

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

ISO TARIFF APPENDIX B

Scheduling Coordinator Agreement

Scheduling Coordinator Agreement

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

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

and

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

Whereas:

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

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

NOW IT IS HEREBY AGREED as follows:

1. **Definitions**

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

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

2. **Covenant of the Scheduling Coordinator**

The Scheduling Coordinator agrees that:

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

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

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

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

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

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

3. **Term and Termination**

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

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

4. **Assignment**

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

5. **Partial Invalidity**

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

6. **Settlement Account**

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

7. **Notices**

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

ISO:

Name of Primary Representative:____________________________________

Name of Alternative Representative:_________________________________

Address: ____

____

State:________________ Zip Code: ________________

E-Mail Address: ____

Phone No:____

Fax No:____

Scheduling Coordinator:

Name of Primary Representative: ____________________________________

Name of Alternative Representative: _________________________________

Address: ____

State: ______________ Zip Code:________________

E-Mail Address: ____________________________________

Phone No:____

Fax No:____

Settlement Account No:____

Title:____

Sort Code:____

Bank:____

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

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

9. **Electronic Contracting.**

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

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

ISO:

By: __________________ __________________ _________________
Name Title Date

Scheduling Coordinator:

By: __________________ __________________ _________________
Name Title Date

ISO TARIFF APPENDIX C

ISO Scheduling Process

Day-Ahead Schedule Timeline

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

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

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

ISO TARIFF APPENDIX D

Black Start Units

Black Start Units

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

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

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

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

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

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

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

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

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

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

(i) dial-up telephone;

(ii) backup radio;

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

ISO TARIFF APPENDIX E

Verification of Submitted Data for Ancillary Services

Verification of Submitted Data for Ancillary Services

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

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

2. Generation Schedules and Bids.

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

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

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

3. Load Schedules and Bids.

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

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

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

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

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

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

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

5. Treatment of Missing Values.

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

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

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

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

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

ISO TARIFF APPENDIX F

Rate Schedules

Schedule 1

Grid Management Charge

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

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

1. The rate in $/MW for the Core Reliability Services 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.

2. 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 forecast Metered Control Area Load in MWh.

3. 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 forecast net uninstructed deviations (netted within a Settlement Interval) in MWh.

4. 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 forecast number of non-zero MW Final Hour-Ahead Schedules, including all awarded Ancillary Service bids.

5. 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 forecast Scheduling Coordinators' inter-zonal scheduled flow (excluding flows pursuant to Existing Contracts) per path in MWh.

6. 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 forecast 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 by Settlement Interval) in MWh.

7. 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 annual informational filing, 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 seven service charges that comprise the Grid Management Charge: (1) Core Reliability Services Charge, (2) Energy Transmission Services Net Energy Charge, (3) Energy Transmission Services Uninstructed Deviations Charge, (4) Forward Scheduling Charge, (5) Congestion Management Charge, (6) Market Usage Charge, and (7) 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, 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 Governing Board shall set forth a budget schedule that shall specify the dates for the budget posting and public workshop events noted below and other significant budget related milestones providing an opportunity for public input.

Budget Posting

The ISO will post on its Internet site the preliminary proposed ISO operating and capital budget to be effective during the subsequent fiscal year, and the projected billing determinant volumes used to develop the rate for each component of the Grid Management Charge.

Public Workshop

Subsequent to the website posting, and prior to (i) the ISO Governing Board approval of the budget and (ii) the submission of the informational filing described in the next paragraph of this Part D, the ISO shall hold a public budget workshop where it will provide an overview of and answer questions from stakeholders on the proposed budget, cost allocation, and the charges for each of the ISO's services for the following year.

Annual Informational Filing

The ISO will make a filing each year no later than December 15, or the first Business Day thereafter, at FERC that shall contain projected cost data on the ISO presented in conformance with the budget approved by the ISO Governing Board and the FERC Uniform System of Accounts (USOA). This filing shall contain such information as is required to update the GMC rates resulting from the application of the formulae in Part A of this Schedule for the following calendar year.

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

The Grid Management Charge revenue requirement, determined in accordance with Part C of this Schedule 1, shall be allocated to the seven service charges specified in Part A of this Schedule 1 as follows. Expenses projected to be recorded in each cost center shall be allocated among the seven charges in accordance with the allocation factors listed in Table 1 to this Schedule 1. In the event the ISO budgets for projected expenditures for cost centers are not specified in Table 1 to this Schedule, 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 seven charges in accordance with the allocation factors listed in Table 1 to this Schedule 1. Capital expenditures shall be allocated among the seven charges in accordance with the allocation factors listed in Table 2 to this Schedule 1 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 7 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.

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.

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%**	**22%**	**4%**	**5%**	**10%**	**16%**	**100%**
1111	CEO - General	44%	22%	4%	5%	10%	16%	100%
1241	MD02	7%	0%	14%	11%	28%	40%	100%
1521	Grid Planning	63%	38%	0%	0%	0%	0%	100%
1300	**Finance Division**	**44%**	**21%**	**4%**	**4%**	**10%**	**16%**	**100%**
1311	CFO - General	44%	21%	4%	4%	10%	16%	100%
1321	Accounting	44%	22%	4%	5%	10%	16%	100%
1331	Financial Planning and Treasury	44%	22%	4%	5%	10%	16%	100%
1351	Facilities	44%	21%	4%	4%	10%	17%	100%
1361	Security & Corporate Services	44%	21%	4%	4%	10%	17%	100%

1400	**Information Services Division**	**38%**	**7%**	**10%**	**5%**	**9%**	**31%**	**100%**
1411	Chief Information Officer	38%	7%	10%	5%	9%	31%	100%
1422	Corporate & Enterprise Applications	33%	7%	1%	25%	13%	21%	100%
1424	Asset Management	35%	6%	11%	5%	11%	32%	100%
1431	End User Support	38%	14%	8%	3%	9%	27%	100%
1432	Computer Operations and Infrastructure Services	34%	9%	12%	3%	9%	33%	100%
1433	Network Services	43%	12%	9%	3%	9%	24%	100%
1441	Outsourced Contracts	42%	11%	10%	3%	9%	25%	100%
1442	Production Support	25%	0%	18%	3%	8%	47%	100%
1451	Information Support Services	25%	0%	18%	3%	8%	47%	100%
1461	Control Systems	96%	2%	0%	0%	1%	1%	100%
1462	Field Data Acquisition System (FDAS)	21%	0%	0%	0%	0%	79%	100%
1463	Operations Systems Services	50%	3%	6%	1%	6%	33%	100%
1466	Enterprise Applications	48%	7%	1%	1%	3%	39%	100%
1467	Settlement Systems Services	27%	11%	2%	2%	5%	52%	100%
1468	Corporate Application Support and Administration	44%	21%	4%	4%	10%	17%	100%
1469	Analytical and Reporting Applications	10%	0%	0%	65%	25%	0%	100%
1471	IT Planning	25%	0%	18%	3%	8%	47%	100%
1481	Markets and Scheduling System Services	47%	3%	24%	3%	18%	6%	100%
1482	Market Systems Support Services	45%	1%	19%	6%	24%	6%	100%
1500	**Grid Operations Division**	**67%**	**33%**	**0%**	**0%**	**0%**	**0%**	**100%**
1511	VP Grid Operations	67%	33%	0%	0%	0%	0%	100%
1542	Outage Coordination	95%	5%	0%	0%	0%	0%	100%
1543	Loads and Resources	49%	51%	0%	0%	0%	0%	100%
1544	Real-Time Scheduling	60%	40%	0%	0%	0%	0%	100%
1545	Grid Operations	67%	33%	0%	0%	0%	0%	100%
1546	Security Coordination	100%	0%	0%	0%	0%	0%	100%
1547	Engineering and Maintenance	46%	54%	0%	0%	0%	0%	100%
1548	OSAT Group - General	93%	7%	0%	0%	0%	0%	100%
1549	Operations Training	50%	50%	0%	0%	0%	0%	100%
1554	Special Projects Engineering	43%	57%	0%	0%	0%	0%	100%

1555	Operations Support Group	56%	44%	0%	0%	0%	0%	100%

1558	Transmission Maintenance	58%	42%	0%	0%	0%	0%	100%
1559	Operations Application Support	60%	40%	0%	0%	0%	0%	100%
1561	Operations Engineering South	65%	35%	0%	0%	0%	0%	100%
1562	Operations Engineering North	55%	45%	0%	0%	0%	0%	100%
1563	Operations Coordination	75%	25%	0%	0%	0%	0%	100%
1564	Operations Scheduling	100%	0%	0%	0%	0%	0%	100%
1565	Pre-Scheduling and Support	77%	23%	0%	0%	0%	0%	100%
1566	Regional Coordination - General	100%	0%	0%	0%	0%	0%	100%
1600	**Legal and Regulatory Division**	**36%**	**22%**	**4%**	**7%**	**17%**	**15%**	**100%**
1611	VP General Counsel - General	36%	22%	4%	7%	17%	15%	100%
1631	Legal and Regulatory	44%	22%	4%	5%	10%	16%	100%
1641	Market Analysis	15%	26%	0%	20%	31%	7%	100%
1642	Market Surveillance Committee	25%	25%	0%	25%	25%	0%	100%
1651	ISO Governing Board	44%	22%	4%	5%	10%	16%	100%
1661	Compliance - General	22%	20%	12%	0%	29%	17%	100%
1662	Compliance - Audits	8%	0%	0%	0%	50%	42%	100%
1700	**Market Services Division**	**17%**	**2%**	**9%**	**9%**	**20%**	**41%**	**100%**
1711	VP Market Services - General	17%	2%	9%	9%	20%	41%	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%	20%	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%	7%	0%	0%	0%	50%	100%
1741	Client Relations	0%	0%	0%	0%	0%	100%	100%
1751	Market Operations - General	31%	0%	15%	15%	35%	4%	100%
1752	Manager of Markets	27%	5%	27%	22%	18%	0%	100%
1753	Market Engineering	21%	0%	0%	28%	43%	7%	100%
1755	Business Solutions	6%	0%	47%	12%	29%	6%	100%
1756	Market Quality - General	0%	0%	0%	0%	71%	29%	100%
1757	Market Integration	7%	0%	30%	30%	26%	7%	100%

1800	**Corporate and Strategic Development Division**	**44%**	**21%**	**4%**	**4%**	**10%**	**16%**	**100%**
1811	VP Corporate and Strategic Development - General	44%	21%	4%	4%	10%	16%	100%
1821	Communications	44%	22%	4%	5%	10%	16%	100%
1831	Strategic Development	44%	22%	4%	5%	10%	16%	100%
1841	Human Resources	44%	21%	4%	4%	10%	17%	100%
1851	Project Office	44%	22%	4%	5%	10%	16%	100%
1861	Regulatory Policy	44%	22%	4%	5%	10%	16%	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	37%	12%	9%	5%	11%	25%	100%
Debt Service Related Allocations		33%	8%	15%	5%	9%	29%	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%	0%	22%	3%	7%	45%	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%	21%	4%	4%	10%	17%	100%
CHASE	44%	21%	4%	4%	10%	17%	100%
Common Information Model (CIM)	100%	0%	0%	0%	0%	0%	100%
Compliance (Blaze)	19%	16%	10%	0%	33%	22%	100%
Congestion Management (CONG) (Component of SA)	10%	0%	0%	65%	25%	0%	100%
Congestion Reform-DSOW	50%	0%	0%	50%	0%	0%	100%
Congestion Revenue Rights (CRR)	0%	0%	0%	80%	20%	0%	100%
DataWarehouse	24%	18%	6%	9%	24%	18%	100%
Dept. of Market Analysis Tools (SAS/MARS)	15%	26%	0%	20%	31%	7%	100%
Dispute Tracking System (Remedy)	0%	0%	0%	0%	0%	100%	100%
Documentum	44%	21%	4%	4%	10%	17%	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%	21%	4%	4%	10%	17%	100%
IBM Contract	37%	14%	10%	4%	9%	26%	100%
Integrated Forward Market (IFM)	10%	0%	35%	0%	55%	0%	100%
Internal Development	23%	0%	22%	3%	7%	45%	100%
Interzonal Congestion Management reform - Real Time	50%	0%	0%	50%	0%	0%	100%
Land and Building Costs	44%	21%	4%	4%	10%	17%	100%
Local Area Network (LAN)	44%	21%	4%	4%	10%	17%	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	7%	0%	14%	11%	28%	40%	100%
Meter Data Acquisition System (MDAS)	0%	0%	0%	0%	0%	100%	100%
Miscellaneous (2004 related projects)	23%	0%	22%	3%	7%	45%	100%
Monitoring (Tivoli)	23%	0%	22%	3%	7%	45%	100%
New Resource Interconnection (NRI)	100%	0%	0%	0%	0%	0%	100%
New System Equipment (replacement of owned equipment)	23%	0%	22%	3%	7%	45%	100%
NT/web servers	44%	21%	4%	4%	10%	17%	100%
NT-servers	44%	21%	4%	4%	10%	17%	100%

Oracle Enterprise Manager (OEM)	27%	0%	18%	5%	9%	41%	100%
Office Automation - desktop/laptop (OA)	44%	21%	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%	94%	0%	6%	0%	100%
Physical Facilities Software Application/Furniture/Leasehold Improvements	44%	21%	4%	4%	10%	17%	100%
Process Information System (PI)	80%	0%	0%	0%	10%	10%	100%
Rational Buyer	100%	0%	0%	0%	0%	0%	100%
Real Time Energy Dispatch System (REDS)	100%	0%	0%	0%	0%	0%	100%
Real Time Nodal Market	35%	0%	10%	0%	55%	0%	100%
Reliability Management System (RMS)	100%	0%	0%	0%	0%	0%	100%
Remedy (related to Transmission Registry, New Resource Interconnection, and Resource Registry)	100%	0%	0%	0%	0%	0%	100%
Remote Intelligent Gateway (RIG) & Data Processing Gateway (DPG)	100%	0%	0%	0%	0%	0%	100%
Resource Register (RR)	100%	0%	0%	0%	0%	0%	100%

RMR Application Validation Engine (RAVE)	100%	0%	0%	0%	0%	0%	100%
Scheduling & Logging for ISO California (SLIC)	65%	0%	15%	5%	15%	0%	100%
Scheduling Architecture (SA)	24%	0%	20%	26%	30%	0%	100%
Scheduling Infrastructure (SI)	0%	0%	94%	0%	6%	0%	100%
Scheduling Infrastructure Business Rules (SIBR)	0%	0%	94%	0%	6%	0%	100%
Security Constrained Economic Dispatch (SCED)	40%	0%	0%	0%	60%	0%	100%
Security- External/Physical	44%	21%	4%	4%	10%	17%	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%	21%	4%	4%	10%	17%	100%
Startup Costs through 3/31/98, Working Capital-3 months	44%	21%	4%	4%	10%	17%	100%
Storage (EMC symmetrix)	19%	10%	14%	4%	12%	42%	100%
System Equipment Buyouts (lease buyouts)	43%	1%	7%	2%	11%	36%	100%
Telephone/PBX	44%	21%	4%	4%	10%	17%	100%
Training Systems	23%	0%	22%	3%	7%	45%	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	54%	1%	11%	16%	17%	2%	100%
Utilities - System i.e. Print drivers	23%	0%	22%	3%	7%	45%	100%
Vitria (Middleware)	23%	0%	22%	3%	7%	45%	100%
Wide Area Network (WAN)	41%	2%	19%	1%	8%	29%	100%

Capital Expenditures for Systems not Specified	32%	7%	15%	6%	11%	29%	100%

<u>Table 3</u>

<u>Reallocation Factors for Projected Unrecovered Portion of Settlements, Metering, and Client Relations Revenue Requirement</u>

	CRS	ETS	FS	CM	MU	SMCR	Total
Functional Association of Settlements, Metering, and Client Relations	0.0%	70.3%	0.0%	8.2%	21.4%	0.0%	100.0%

Schedule 2

Other Charges

Voltage Support Service

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

Regulation Service

Regulation Obligation:

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

Regulation Rates:

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

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

Spinning Reserve Service

Spinning Reserve Obligation:

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

Spinning Reserve Rates:

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

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

Non-Spinning Reserve Service

Non-Spinning Reserve Obligation:

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

Non-Spinning Reserve Rates:

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

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

Replacement Reserves

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

Black Start Capability

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

Imbalance Energy Charges

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

Replacement Reserve Charge

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

Unaccounted for Energy

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

Transmission Losses Imbalance Charges

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

Access Charges

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

Usage Charges

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

Default Usage Charge

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

Grid Operations Charge for Intra-Zonal Congestion

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

Wheeling Access Charges

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

Charge for Failure to Conform to Dispatch Instructions

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

Reliability Must-Run Charge

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

FERC Annual Charge Recovery Rate

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

ISO Tariff Appendix F

Schedule 3

High Voltage Access Charges

1. Objectives and Definitions

1.1 Objectives

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

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

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

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

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

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

1.2 Definitions

(a) Master Definition Supplement

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

(b) Special Definitions for this Appendix

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

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

"TAC Benefit" means the amount, if any, for each year by which the cost of Existing High Voltage Transmission Facilities associated with deliveries of Energy to Gross Loads in the PTO Service Territory is reduced by the implementation of the High Voltage Access Charge described in Schedule 3 to Appendix F. The Tac Benefit of a New Participating TO shall not be less than zero.

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

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

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

3. TAC Areas.

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

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

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

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

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

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

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

4. Transition Date

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

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

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

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

4.5 **Conversion of Existing Rights.** During the process by which a New Participating TO executes the Transmission Control Agreement, the ISO and potential New Participating TO that has an obligation to serve Load shall determine the amount of FTRs to be allocated to the New Participating TO for each Existing Right that the New Participating TO converts to Converted Rights. In making that determination, the ISO will consider the amount of contracted transmission capacity, the firmness of the contracted transmission capacity, and other characteristics of the contracted transmission capacity to determine the amount of FTRs to be given to the New Participating TO in accordance with Section 9.4.3 of the ISO Tariff.

5. Determination of the Access Charge.

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

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

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

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

$$HVAC = HVAC_A + HVAC_I$$

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

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

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

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

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

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

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

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

5.7 The Transition Charge shall be calculated separately for each Participating TO by dividing (i) the net difference between (1) the Participating TO's payment responsibility, if any, under Section 8.6 of the ISO Tariff and Section 7 of this Schedule 3; and (2) the amount, if any, payable to the Participating TO in accordance with Section 8.6 of the ISO Tariff and Section 7 of this Schedule 3; by (ii) the total of all forecasted Gross Load in the PTO Service Territory of the Participating TO, including the UDC and/or MSS Operator. If greater than zero, the Transition Charge shall be collected with the High Voltage Access Charge. If less than zero, the Transition Charge shall be credited with the High Voltage Access Charge. The amount of each Participating TO's NHVTRR shall not be included in the Transition Charge calculation.

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

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

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

6 High Voltage Transmission Revenue Requirement.

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

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

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

7 Limitation

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

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

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

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

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

8. Updates to High Voltage Access Charges.

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

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

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

9. Approval of Updated High Voltage Revenue Requirements

9.1 Participating TOs will make the appropriate filings at FERC to establish their Transmission Revenue Requirements for their Low Voltage Access Charges and the applicable High Voltage Access Charges, and to obtain approval of any changes thereto. All such filings with the FERC will include a separate appendix that states the HVTRR, LVTRR (if applicable) and the appropriate Gross Load data and other information required by the FERC to support the Access Charges. The Participating TO will provide a copy of its filing to the ISO and the other Participating TOs in accordance with the notice provisions in the Transmission Control Agreement.

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

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

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

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

(b)

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

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

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

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

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

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

11.1 Each Participating TO shall allocate its Transmission Revenue Requirement between the High Voltage Transmission Revneue Requirement and Low Voltage Transmission Revenue Requirement based on the “Procedure for Division of Certain Costs Between the High and Low Voltage Transmission Access Charges” posted on the ISO Home Page.

ISO Tariff Appendix F

Schedule 4

Participating Intermittent Resources Forecasting Fee

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

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

Methodology for Developing the Weighted Average Rate for Wheeling Service

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

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

Where:

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

P_n = The applicable Wheeling Access Charge rate for a TAC Area or Participating TO_n in $/kWh as set forth in Section 7.1.4 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 2.4.4 of the ISO Tariff.

n = the number of Participating TOs from 1 to n

ISO TARIFF APPENDIX I

ISO Congestion Management Zones

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 & Capabilities

End-Use Meter Standards & Capabilities Part A

END-USE METER STANDARDS & CAPABILITIES

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

[Not Used]

ISO TARIFF APPENDIX L

ISO Protocols

INDEX

ANCILLARY SERVICES REQUIREMENTS PROTOCOL

ANCILLARY SERVICES REQUIREMENTS PROTOCOL

Table of Contents

ANCILLARY SERVICES REQUIREMENTS PROTOCOL (ASRP)

ASRP 1 OBJECTIVES, DEFINITIONS AND SCOPE

ASRP 1.1 Objectives

(a) The ISO needs to have available to it sufficient Ancillary Services of a standard necessary to enable it to maintain the reliability of the ISO Controlled Grid.

(b) This Protocol describes the ISO's basis for determining its Ancillary Services requirements and the required standard for each Ancillary Service.

(c) These requirements and standards apply to all Ancillary Services whether self-provided or procured by the ISO.

(d) This Protocol also describes the means by which the ISO will monitor performance of these Ancillary Services to ensure that the required standards are met and maintained.

ASRP 1.2 Definitions

ASRP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is to a Section or an Appendix of the ISO Tariff. References to ASRP are to this Protocol or to the stated paragraph of or Appendix to this Protocol.

ASRP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following expression shall have the meaning set opposite it:

"Area Control Error (ACE)" means 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.

"Dynamic Schedule" means 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.

ASRP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol 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 Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

ASRP 1.3 Scope

ASRP 1.3.1 Scope of Application to Parties

This Protocol applies to the ISO and to the following:

(a) Participating Generators

(b) Operators

(c) UDCs

(d) Providers of Curtailable Demand

(e) Scheduling Coordinators

(f) Metered Subsystem Operators.

ASRP 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.

ASRP 2 ANCILLARY SERVICES STANDARDS

ASRP 2.1 Basis of Standards

ASRP 2.1.1 Basic criteria

(a) The ISO shall base its Ancillary Services standards upon the Western Electricity Coordinating Council (WECC) Minimum Operating Reliability Criteria (MORC) and North American Electric Reliability Council (NERC) Criteria to the extent they are applicable to the ISO Controlled Grid.

(b) 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.

ASRP 2.2 Review of Standards

ASRP 2.2.1 Grid Operations Committee Review

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

ASRP 2.2.2 Contents of Grid Operations Committee Reviews

Periodic reviews may include, but are not limited to:

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

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

(c) analysis of compliance with NERC and 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.

ASRP 2.3 Communications

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

ASRP 3 ANCILLARY SERVICE OBLIGATIONS FOR SCHEDULING COORDINATORS

ASRP 3.1 Ancillary Service Obligations

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

ASRP 3.2 Right to Self-Provide

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

ASRP 4 REGULATION STANDARDS

ASRP 4.1 Standard for Regulation: Quantity Needed

ASRP 4.1.1 Basis for Standard

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

ASRP 4.1.2 Determination of Regulation Quantity Needed

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

ASRP 4.1.3 Percentage Determination

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

ASRP 4.1.4 Publication of Estimated Percentage for Day-Ahead Market

In accordance with the requirements of SP 3.2.1, the ISO will publish on 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.

ASRP 4.1.5 Publication of Estimated 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.

ASRP 4.1.6 Additional Regulation Requirement

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

ASRP 4.2 Standard for Regulation: Performance

ASRP 4.2.1 Operating Characteristics of Generating Unit

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

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

(b) it must be capable of achieving at least the ramp rates (increase and decrease in MW/minute) stated in 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; and

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

ASRP 4.2.2 Operational EMS/SCADA Equipment

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

ASRP 4.3 SC's Obligation for Regulation

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

ASRP 4.4 Standard for Regulation: Control

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

ASRP 4.4.1 Dynamic Scheduling of Regulation from External Resources

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

ASRP 4.5 Standard for Regulation: Procurement

ASRP 4.5.1 Procurement of Non Self-Provided Regulation

Regulation necessary to meet ISO requirements not met by self-provided Regulation will be procured by the ISO as described in the ISO Tariff.

ASRP 4.5.2 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 Appendix A to this Protocol.

ASRP 4.5.3 [Not Used]

ASRP 4.5.4 [Not Used]

ASRP 5 OPERATING RESERVE STANDARDS

The ISO needs, as a minimum, Operating Reserve, consisting of Spinning Reserve and Non-Spinning Reserve, sufficient to meet WECC MORC. The Operating Reserve requirement shall be 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. This Operating Reserve requirement does not include the Operating Reserve required to cover the Generation or services described in ASRP 5.2(a) and (b).

ASRP 5.1 Standard for Spinning Reserve: Quantity Needed

ASRP 5.1.1 Minimum Spinning Reserve Quantity

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.

ASRP 5.1.2 Providing both Spinning Reserve and Regulation

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.

ASRP 5.2 Standard for Non-Spinning Reserve: Quantity Needed

The required quantity of Non-Spinning Reserve shall be equal to the required quantity of Operating Reserve less the quantity of Spinning Reserve determined in ASRP 5.1 plus;

(a) an amount of Non-Spinning Reserve equal to Interruptible Imports (which must either be self-provided by the Scheduling Coordinators responsible for the Interruptible Imports from resources within the ISO Controlled Grid or purchased from the ISO); and

(b) an amount of Non-Spinning Reserve equal to on-demand obligations to other entities or Control Areas (which must be self-provided by the Scheduling Coordinators responsible for the on-demand obligations from resources within the ISO Controlled Grid).

Scheduling Coordinators may self-provide their allocated quantity of Non-Spinning Reserve under ASRP 5.2(a) and (b) from Spinning Reserve not already committed to the ISO, if they wish.

ASRP 5.3 Standard for Spinning Reserve: Performance

ASRP 5.3.1 Spinning Reserve Capability

Each Generating Unit or external import of a System Resource scheduled to provide 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.

ASRP 5.3.2 Availability

Each Participating Generator shall ensure:

(a) that its Generating Units scheduled to provide Spinning Reserve are available for Dispatch throughout the Settlement Period for which it has been scheduled; and

(b) that its Generating Units scheduled to provide Spinning Reserve are responsive to frequency deviations throughout the Settlement Period for which they have been scheduled.

ASRP 5.4 Standard for Non-Spinning Reserve Performance

ASRP 5.4.1 Non-Spinning Reserve Resources

Non-Spinning Reserve may be provided by, among others, the following resources:

(a) Demand which can be reduced by Dispatch;

(b) interruptible exports;

(c) on-demand rights from other entities or Control Areas;

(d) off line Generating Units qualified to provide Non-Spinning Reserve; and

(e) external imports of System Resources.

ASRP 5.4.2 Non-Spinning Reserve Capability

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 for at least two hours.

ASRP 5.4.3 Availability

Each provider of Non-Spinning Reserve must ensure that its resources scheduled to provide Non-Spinning Reserve are available for Dispatch throughout the Settlement Period for which they have been scheduled.

ASRP 5.5 SC's Obligation for Operating Reserve

ASRP 5.5.1 Obligation for Spinning and Non-Spinning Reserve

Except for the requirement for Non-Spinning Reserve referred to in paragraph ASRP 5.5.2, each Scheduling Coordinator's Operating Reserve obligation in each Zone shall be pro rata based upon the same proportion as 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 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.

ASRP 5.5.2 Additional Non-Spinning Reserve Requirements

Additional Non-Spinning Reserve required pursuant to ASRP 5.2(a) and (b) is the responsibility of the Scheduling Coordinator implementing such Schedules and is in addition to the obligation provided in paragraph ASRP 5.5.1.

ASRP 5.6 Standard for Spinning Reserve: Control

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

ASRP 5.7 Standard for Non-Spinning Reserve: Control

Each provider of 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 Non-Spinning Reserve resource and must ensure that its resource can be at the Dispatched operating level or condition within ten minutes after issue of the Dispatch instruction.

ASRP 5.8 Standard for Operating Reserve: Procurement

ASRP 5.8.1 Procurement of Non Self-Provided Operating Reserve

Operating Reserve necessary to meet ISO requirements not met by self-provided Operating Reserve will be procured by the ISO as described in the ISO Tariff.

ASRP 5.8.2 Procurement Not Limited to ISO Control Area

The ISO will procure Spinning and Non-Spinning Reserves from Generating Units operating within the ISO Control Area and external imports of System Resources.

ASRP 5.8.3 Spinning Reserve Certification and Testing Requirements

Spinning Reserve may only be provided from

(1) Generating Units;

(2) System Resources from external imports; or

(3) System Units;

which have been certified and tested by the ISO using the process defined in Appendix B to this Protocol.

ASRP 5.8.4 Non-Spinning Reserve Certification and Testing Requirements

Non-Spinning Reserve may only be provided from resources including

(1) Loads;

(2) Generating Units;

(3) System Resources from external imports; and

(4) System Units;

which have been certified and tested by the ISO using the process defined in Appendix C to this Protocol.

ASRP 5.8.5 Self-Provision of Operating Reserve

Scheduling Coordinators may self-provide Spinning and Non-Spinning Reserves from resources outside the ISO Control Area.

ASRP 6 REPLACEMENT RESERVE STANDARDS

ASRP 6.1 Standard for Replacement Reserve: Quantity Needed

ASRP 6.1.1 Basis for Standard

The ISO needs sufficient Replacement Reserve to be available to allow restoration of Dispatched Operating Reserve within sixty minutes to its Set Point scheduled for the Settlement Period concerned.

ASRP 6.1.2 Replacement Reserve Requirements

The ISO shall have discretion to determine the quantity of Replacement Reserve it requires in each Zone. The ISO shall make its determination of the required quantity of Replacement Reserve based on:

(a) analysis of the deviation between aggregate forecast Demands supplied by Scheduling Coordinators and that forecast by ISO;

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

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

(d) analysis of patterns of unexpected transmission Outages;

(e) analysis of seasonal variations that may require additional Replacement Reserves; and

(f) other factors influencing the ISO Controlled Grid's ability to meet Applicable Reliability Criteria.

ASRP 6.2 Standard for Replacement Reserve: Performance

ASRP 6.2.1 Replacement Reserve Supply Capability

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.

ASRP 6.2.2 Replacement Reserve Availability

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

ASRP 6.2.3 Resources already Providing Ancillary Service

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.

ASRP 6.3 Scheduling Coordinator's Obligation for Replacement Reserve

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

ASRP 6.4 Standard for Replacement Reserve: Control

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.

Issued by: Charles F. Robinson, Vice President and General Counsel
Issued on: March 11, 2004 Effective: October 13, 2000

ASRP 6.5 Standard for Replacement Reserve: Procurement

ASRP 6.5.1 Procurement of Non Self-Provided Replacement Reserve

Replacement Reserve necessary to meet ISO requirements not met by self-provided Replacement Reserve will be procured by the ISO as described in the ISO Tariff.

ASRP 6.5.2 Procurement Not Limited to ISO Control Area

The ISO will procure Replacement Reserves from Generating Units operating within the ISO Control Area and external imports of System Resources.

ASRP 6.5.3 Self-Provision of Replacement Reserve

Scheduling Coordinators may self-provide Replacement Reserves as external imports from System Resources located outside the ISO Control Area.

ASRP 6.5.4 Certification and Testing Requirements

Replacement Reserve may only be provided from resources including

(1) Loads;

(2) Generating Units;

(3) System Resources from external imports; and

(4) System Units

which have been certified and tested by the ISO using the process defined in Appendix C to this Protocol.

ASRP 7 VOLTAGE SUPPORT STANDARDS

ASRP 7.1 Standard for Voltage Support: Quantity Needed

The ISO shall determine on a daily basis for each Settlement Period for each Trading 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 Demand scheduled in each Settlement Period of the Day-Ahead Market. The ISO shall issue daily voltage schedules (Dispatch instructions) to Generators, Participating TOs and UDCs for each Trading Day, which are required to be maintained for ISO Controlled Grid reliability.

ASRP 7.2 Standard for Voltage Support: Performance

ASRP 7.2.1 Automatic Voltage Regulation Requirement

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.

ASRP 7.2.2 Compensation for Operating Outside of Range

The ISO will not compensate Generators for operating their Generating Units within the power factor band of 0.90 lag to 0.95 lead. If the ISO requires additional Voltage Support in the short term it may instruct a reduction in a Generating Unit's MW output so that it operates outside its specified power factor range. The ISO will compensate Generators for this service as provided in the ISO Tariff.

ASRP 7.3 Standard for Voltage Support: Distribution and Location

Each Generator, Participating TO and UDC shall ensure that sufficient Voltage Support is available in the vicinity of each designated substation bus to maintain voltage within the Voltage Limits prescribed by the ISO in its voltage schedules for each Settlement Period. Each Generator, Participating TO and UDC shall provide sufficient reactive supply in each local area to take into account real power losses created by reactive power flow on the system. Reactive power flow at Scheduling Points shall be maintained within a power factor bandwidth of 0.97 lag to 0.99 lead.

ASRP 7.4 Standard for Voltage Support: Control

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.

ASRP 7.5 Standard for of Voltage Support: Procurement

ASRP 7.5.1 Long-Term Voltage Support

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.

ASRP 7.5.2 Certification and Testing Requirements

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 Appendix E to this Protocol.

ASRP 8 BLACK START STANDARDS

ASRP 8.1 Standard for Black Start: Quantity Needed

ASRP 8.1.1 Determination of Black Start Capability

The ISO shall determine the amount and location of Black Start capability it requires by reference to contingency studies which will be used as the basis of the ISO's emergency plans.

ASRP 8.1.2 Factoring in Failed Starts

The ISO shall, in determining the quantity needed, account for the probability that some Black Start Generating Units may fail to start or that transmission system damage may prevent some Black Start Generating Units from serving their intended loads.

ASRP 8.1.3 Submission of Load Restoration Time Requirements

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

ASRP 8.2 Standard for Black Start: Performance

ASRP 8.2.1 10-Minute Start-Up Capability

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.

ASRP 8.2.2 Reactive Capability

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.

ASRP 8.2.3 12-Hour Minimum Output Capability

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.

ASRP 8.3 Standard for Black Start: Location

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.

ASRP 8.4 Standard for Black Start: Control

ASRP 8.4.1 Voice Communication Requirement

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.

ASRP 8.4.2 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.

ASRP 8.5 Standard for Black Start: Procurement

ASRP 8.5.1 Initial Procurement

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.

ASRP 8.5.2 Certified Generating Units Requirement

Black Start capability may only be provided from Generating Units which have been certified and tested by the ISO using the process defined in Appendix F to this Protocol.

ASRP 9 TESTING FOR STANDARD COMPLIANCE

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. Scheduling Coordinators for Ancillary Service resources being tested will be compensated for Energy output or Demand reduction provided pursuant to such tests in accordance with the ISO Tariff.

ASRP 9.1 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.

ASRP 9.2 Compliance Testing for Spinning Reserve

The ISO may test the capability of any Generating Unit, System Unit or external import of a System Resource providing Spinning Reserve by issuing unannounced Dispatch instructions requiring the Generating Unit, System Unit or external import of a System Resource to ramp up to its stated ten minute capability 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.

ASRP 9.3 Compliance Testing for Non-Spinning Reserve

ASRP 9.3.1 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.

ASRP 9.3.2 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.

ASRP 9.4 Compliance Testing for Replacement Reserve

ASRP 9.4.1 Compliance Testing of a Generating 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.

ASRP 9.4.2 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.

ASRP 9.5 Compliance Testing for Voltage Support

ASRP 9.5.1 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.

ASRP 9.5.2 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.

ASRP 9.6 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.

ASRP 9.7 Consequences of Failure to Pass Compliance Testing

ASRP 9.7.1 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.

ASRP 9.7.2 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 ASRP 11.

ASRP 10 PERFORMANCE AUDITS FOR STANDARD COMPLIANCE

In addition to testing under ASRP 9, 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.

ASRP 10.1 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.

ASRP 10.2 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.

ASRP 10.3 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.

ASRP 10.4 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.

ASRP 10.5 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.

ASRP 10.6 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.

ASRP 10.7 Consequences of Failure to Pass Performance Audits

ASRP 10.7.1 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

ASRP 10.7.2 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 ASRP 11 shall come into effect.

ASRP 11 SANCTIONS FOR POOR PERFORMANCE

ASRP 11.1 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.

ASRP 11.2 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.

ASRP 11.3 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 ASRP 11.2 or carried out by the ISO under ASRP 9; or

(b) the expiry 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.

ASRP 11.4 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 Appendix to this ASRP.

ASRP 12 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

ANCILLARY SERVICES REQUIREMENTS PROTOCOL

APPENDICES A-F

APPENDIX 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.

APPENDIX 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.**

APPENDIX 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.

APPENDIX 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.**

APPENDIX 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.

APPENDIX 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.

DEMAND FORECASTING PROTOCOL

DEMAND FORECASTING PROTOCOL

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DEMAND FORECASTING PROTOCOL (DFP)

DFP 1 Objectives, Definitions and Scope

DFP 1.1 Objectives

The objective of the DFP is to set forth procedures for submission of Demand Forecasts which will provide information to the ISO for projecting future Demand requirements to be served by the ISO Controlled Grid. The ISO shall utilize such forecasts to enable it to assess System Reliability and carry out its functions under the Scheduling Protocol (SP) and the Outage Coordination Protocol (OCP).

DFP 1.2 Definitions

DFP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix refers to a Section or an Appendix of the ISO Tariff unless otherwise indicated. References to DFP are to this Protocol or to the stated paragraph of this Protocol.

DFP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meaning set opposite them:

"Annual Peak Demand Forecast" means a Demand Forecast of the highest Hourly Demand in any hour in a calendar year, in MW.

"Congestion Zone" means a Zone identified as an Active Zone in Appendix I of the ISO Tariff.

"Hourly Demand" means the average of the instantaneous Demand integrated over a single clock hour, in MW.

"Weekly Peak Demand Forecast" means a 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.

DFP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol 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 Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

DFP 1.3 Scope

DFP 1.3.1 Scope of Application to Parties

The DFP applies to the following entities:

(a) Scheduling Coordinators (SCs);

(b) Utility Distribution Companies (UDCs); and

(c) the ISO.

DFP 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.

DFP 2 Scheduling Coordinator Demand Forecast Responsibilities

DFP 2.1 Data to be Submitted to the ISO by SCs

At the time specified in DFP 2.3, each SC shall submit to the ISO its Weekly Peak Demand Forecast by Congestion Zone reflecting (1) the Weekly Peak Demand Forecasts of the UDCs that it proposes to Schedule and (2) any other non-UDC Demand that it proposes to Schedule. All Weekly Peak Demand Forecasts submitted shall include Demand Forecasts for the following 52 weeks.

DFP 2.2 Format of Demand Forecasts

Demand Forecasts must be submitted to the ISO electronically in the format set forth in Schedule 1 of this Protocol.

DFP 2.3 Timing of Submission of Demand Forecasts

The Demand Forecasts described in DFP 2.1 shall be submitted by SCs to the ISO on a monthly basis by noon of the 18th working day of the month.

DFP 2.4 Forecast Standards

DFP 2.4.1 Avoiding Duplication

SCs submitting Demand Forecasts to the ISO shall ensure, to the best of their ability, that any Demand they are forecasting is not included in another SC's Demand Forecasts. To accomplish this, each SC's Demand Forecasts should only reflect those End-Use Customers who they actually have under contract and who have notified their UDC or previous SC of their intention to change to another SC, and which are actually scheduled to convert.

DFP 2.4.2 Required Performance

SCs submitting its Demand Forecasts to the ISO shall take all necessary actions to provide Demand Forecasts that reflect the best judgment of the submitting SC to help avoid potential System Reliability concerns and to enable the ISO to administer a meaningful market for Energy and Ancillary Services. From time to time the ISO may publish information on the accuracy of SC Demand Forecasts.

DFP 2.4.3 Incomplete or Unsuitable Demand Forecasts

If the Demand Forecasts supplied by a SC to the ISO are, in the ISO's opinion, incomplete or otherwise unsuitable for use, or a particular Demand Forecast has not been supplied by a SC to the ISO as required under this Protocol, the ISO will substitute the last valid Demand Forecast received from the SC in replacement for any incomplete, unsuitable or not supplied Demand Forecasts.

DFP 3 UDC Responsibilities

DFP 3.1 Data to be Submitted to the ISO by UDCs

At the time specified in DFP 3.3, each UDC shall submit to the ISO its Weekly Peak Demand Forecasts by Congestion Zone reflecting the Weekly Peak Demand Forecast for Load expected to be served by facilities under the control of the UDC. All Weekly Peak Demand Forecasts submitted shall include Demand Forecasts for the following 52 weeks.

DFP 3.2 Format of Demand Forecasts

Demand Forecasts must be submitted to the ISO electronically in the format set forth in Schedule 2 of this Protocol.

DFP 3.3 Timing of Submission of Demand Forecasts

The Demand Forecasts described in DFP 3.1 shall be submitted by UDC to the ISO on a monthly basis by noon of the twelfth working day of the month.

DFP 3.4 Forecast Standards

DFP 3.4.1 Avoiding Duplication

Each UDC submitting Demand Forecasts to the ISO and its SC shall ensure, to the best of its ability, that any Demand Forecasts that it is submitting to the ISO and its SC are not duplicated in another SC's Demand Forecasts.

DFP 3.4.2 Required Performance

Each UDC submitting its Demand Forecasts to the ISO and its SC shall take all necessary actions to provide Demand Forecasts that reflect the best judgment of the submitting UDC to help avoid potential System Reliability concerns and to enable the ISO to administer a meaningful market for Energy and Ancillary Services. The ISO may publish information on the accuracy of UDC Demand Forecasts from time to time.

DFP 4 ISO Responsibilities

DFP 4.1 Advisory Control Area Demand Forecasts

The ISO will publish on WEnet and supply to the SCs advisory Control Area 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 the SP.

DFP 4.2 ISO Demand Forecasts

The ISO shall publish monthly on WEnet the following two (2) Demand Forecasts for the next 52 weeks.

(i) Consolidated SC Forecast. This forecast will be developed by adding together the Weekly Peak Demand Forecasts of the individual SCs.

(ii) Independent ISO Forecast. This forecast will be developed by the ISO.

The ISO may, at its discretion, publish on WEnet additional Demand Forecasts for two or more years following the next year.

DFP 5 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

SCHEDULE 1

SC DEMAND FORECAST FORMAT

SC 52 Weeks Load Forecast (for the next 52 operating weeks)

This template is used to post 52 Weeks Load Forecast.

(a) SC's ID code

(b) Forecast Weekly Maximum Generation capacity for each of the next 52 weeks

(c) Forecast Weekly Maximum Demand for each of the next 52 weeks

SCHEDULE 2

UDC DEMAND FORECAST FORMAT

SC/UDC Direct-Access Load Forecast

This template is for use by the SCs to forecast their direct-access loads for each UDC. The forecast must be for seven (7) future days including the current Day-Ahead Market.

(a) SC's ID code

(b) Trading Day of current Day-Ahead Market (month/day/year)

(c) UDC's ID code

(d) Hourly Demand Forecast for the 168 hours beginning with the first hour of the current Day-Ahead Market

DISPATCH PROTOCOL

DISPATCH PROTOCOL

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DISPATCH PROTOCOL (DP)

DP 1 OBJECTIVES, DEFINITIONS AND SCOPE

DP 1.1 Objectives

The objectives of this Protocol are:

(a) to implement those sections of the ISO Tariff which involve real-time and emergency operations;

(b) to describe the real-time Dispatch of the Ancillary Services specified in the Ancillary Services Requirements Protocol (ASRP);

(c) to describe the operational activities of the ISO after all commitments have been made in the Hour-Ahead Market as described in the Scheduling Protocol (SP);

(d) to describe the use of Supplemental Energy bids received by the ISO in accordance with the Schedules and Bids Protocol (SBP); and

(e) to describe how the ISO will meet the operational requirements of NERC and WECC guidelines.

DP 1.2 Definitions

DP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is a reference to a Section or an Appendix of the ISO Tariff. References to DP are to this Protocol or to the stated paragraph of this Protocol.

DP 1.2.2 Special Definitions for this Protocol

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

"Backup ISO Control Center" means the ISO Control Center located in Alhambra, California.

"BEEP" means the Balancing Energy and Ex-Post Pricing software referred to in SP 11.2 which is used to determine the merit order stack.

"Control Area Operator" means the person responsible for managing the real-time operations of a Control Area.

"Dispatch Instruction" means an operating order that is issued by the ISO to a Participant pertaining to real-time operations.

"GCC" means the single point of contact at the grid control center of Southern California Edison Company.

"Primary ISO Control Center" means the ISO Control Center located in Folsom, California.

"Participant" means any of those entities referred to in DP 1.3.1(a)-(f).

"Power System Stabilizer (PSS)" means 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.

"Qualifying Facility" means a qualifying co-generation or small power production facility recognized by FERC.

"Reliability Coordinator" means the person responsible for Security Monitoring in real time for the California Area.

"TOC" means the single point of contact at the transmission operations center of Pacific Gas & Electric Company.

"Total Transfer Capability (TTC)" means 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.

"Western Interconnection" means a network of transmission lines embodied within the WECC Region.

DP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol 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 Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

(e) Time references in this Protocol are references to prevailing Pacific time.

DP 1.3 Scope

DP 1.3.1 Scope of Application to Parties

This Protocol applies to the ISO and to the Participants:

(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.

DP 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.

DP 2 STANDARDS TO BE OBSERVED

DP 2.1 Applicable Reliability Criteria

The ISO shall exercise Operational Control over the ISO Controlled Grid in compliance with all 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).

DP 2.1.1 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.

DP 2.1.2 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.

DP 2.1.3 Local Reliability Criteria (Standards)

The reliability criteria unique to the transmission systems of each of the PTOs established at the later of: (1) the ISO Operations Date or (2) the date upon which a new Participating TO places its facilities under the control of the ISO. Each Participating TO must provide its Local Reliability Criteria to the ISO, as required by the TCA.

DP 2.1.4 NRC (Standards)

The reliability standards published by the NRC from time to time.

DP 2.2 Ancillary Services

The ISO will base its standards for the Dispatch of Ancillary Services upon WECC MORC and ISO Controlled Grid reliability requirements.

DP 2.3 ISO Standards

The ISO Governing Board may establish guidelines more stringent than those established by NERC and WECC as needed for the secure and reliable operation of the ISO Controlled Grid.

DP 2.4 Good Utility Practice (Standards)

When the ISO is exercising Operational Control of the ISO Controlled Grid, the ISO and Participants shall comply with Good Utility Practice. The ISO Tariff defines Good Utility Practice which, for ease of use of the DP, is repeated as follows:

> "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 judgement 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."

DP 2.5 Existing Contracts

The ISO will implement Sections 2.4.3 and 2.4.4 of the ISO Tariff with respect to Existing Contracts after the close of the Hour-Ahead Market and in real time.

DP 2.6 The Role of Participants

In issuing the Dispatch Instructions, the ISO will not intentionally request UDCs, Participating Generators, Generating Unit operators, or SCs 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.

DP 3 SCHEDULING AND REAL-TIME INFORMATION

DP 3.1 Final Schedules

The scheduling process described in the SP 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. 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 SCs' 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.

DP 3.2 Supplemental Energy

In addition to the Final Schedules, Supplemental Energy bids will be available to the ISO real-time dispatchers, as described in the SBP, by forty-five (45) minutes prior to the start of the Settlement Period to which such Supplemental Energy bids apply.

DP 3.3 SC Intertie Schedules

In accordance with the SBP and the SP, SCs shall provide the ISO with Interconnection schedules prepared in accordance with all NERC, WECC and ISO requirements. The provisions of the SBP and the SP shall apply to real-time changes in Interconnection schedules under Existing Contracts.

DP 3.4 Information to be Supplied by SCs

DP 3.4.1 SC Dispatch

Each SC shall be responsible for the scheduling and Dispatch of Generation and Demand in accordance with its Final Schedule.

DP 3.4.2 Generator or Interconnection Schedule Change

Each SC shall keep the ISO appraised 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 SC shall immediately pass to the ISO any information which it receives from a Generator which the Generator provides to the SC pursuant to DP 3.7. Each SC shall immediately pass to the ISO any information it receives from a MSS Operator which the MSS Operator provides to the SC pursuant to DP 3.9.

DP 3.4.3 Verbal Communication with Generators

Normal verbal communication of Dispatch Instructions between the ISO and Generators will be via the relevant SC. Each SC must immediately pass on to the Generator concerned any verbal 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 SC. 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.

DP 3.4.4 Consequences of a Failure to Respond or Inadequate Response

The ISO may apply penalties, fines, economic consequences or the sanctions referred to in DP 9.5.2 for any failure or inadequate response under DP 3.4.3 to the SC 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.

DP 3.5 Information to be Supplied by UDCs

DP 3.5.1 UDC Status Change

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.

DP 3.5.2 UDC Outage Scheduling

Each UDC shall schedule all equipment Outages (or Outages of other equipment that could affect the ISO Controlled Grid) at the point of interconnection with the ISO using the appropriate Outage scheduling procedures described in the OCP.

DP 3.5.3 UDC Outage Emergency Scheduling

Each UDC shall coordinate any requests for emergency Outages on point of interconnection equipment directly with the appropriate ISO Control Center as specified in DP 6.2.

DP 3.6 Information to be Supplied by PTOs

DP 3.6.1 Transmission Status Change

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.

DP 3.6.2 Transmission Outage Scheduling

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 procedure under the OCP.

DP 3.6.3 PTO Emergency Outage Scheduling

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 DP 6.2.

DP 3.7 Information to be Supplied by Generators

DP 3.7.1 Generator Status Change

Each Generator shall immediately inform the ISO, through its respective SC, 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 Generator shall immediately report to the ISO, through its SC 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.

DP 3.7.2 Generator Schedules

In the event that a 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 Generator shall notify the ISO, through its SC at once. If a 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 SC at once.

DP 3.8 Information to be Supplied by Control Area Operators

DP 3.8.1 System Status Change

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.

DP 3.8.2 Scheduling Procedure

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.

DP 3.8.3 Data Exchange

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.

DP 3.8.4 Operational Metering

All provisions in this section DP 3.8 refer to information and data obtained from metering used for Control Area operations and not metering used for billing and settlement.

DP 3.9 [Not Used]

DP 3.9.1 [Not Used]

DP 3.9.2 [Not Used]

DP 3.9.3 [Not Used]

DP 3.9.4 [Not Used]

DP 3.9.5 [Not Used]

DP 4 METHODS OF COMMUNICATIONS

DP 4.1 Methods of Transmitting Dispatch Instructions

DP 4.1.1 Full-Time Communications Facility Requirement

Each Participant 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.

DP 4.2 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 Participant concerned to the Dispatch Instruction.

DP 4.3 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.

DP 4.4 Acknowledgement of Dispatch Instructions

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.

DP 5 ISO FACILITIES AND EQUIPMENT

DP 5.1 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 DP 5 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.

DP 5.2 WEnet Unavailable

DP 5.2.1 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 SCs 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 SCs; and

(c) the ISO will not be able to communicate general information, including emergency information, to any Participants.

DP 5.2.2 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 SC 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 SCs via voice communications as time and manpower allows.

DP 5.3 Primary ISO Control Center – Loss of all Voice Communications

DP 5.3.1 Notification of Loss of Voice Communication

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.

DP 5.3.2 Notification of Restoration of Voice communication

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

DP 5.4 Primary ISO Control Center – Control Center Completely Unavailable

DP 5.4.1 Notification of Loss of Primary ISO Control Center

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.

DP 5.4.2 Backup ISO Control Center Response

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.

DP 5.4.3 Notification of Restoration of Primary ISO Control Center

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.

DP 5.5 Primary ISO Control Center - ISO Energy Management System (EMS) Unavailable

DP 5.5.1 Notification of Loss of EMS

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.

DP 5.5.2 Notification of Restoration of EMS

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.

DP 5.6 Backup ISO Control Center – Loss of all Voice Communications

DP 5.6.1 Notification of Loss of Voice Communication

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.

DP 5.6.2 Notification of Restoration of Voice Communication

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

DP 5.7 Backup ISO Control Center – Control Center Completely Unavailable

DP 5.7.1 Notification of Loss of Backup ISO Control Center

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.

DP 5.7.2 Primary ISO Control Center Response

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.

DP 5.7.3 Notification of Restoration of Backup ISO Control Center

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.

DP 5.8 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.

DP 6 ROUTINE OPERATION OF THE ISO CONTROLLED GRID

DP 6.1 Overview/Responsibility

The ISO shall operate the ISO Controlled Grid in accordance with the standards described in DP 2 and within the limit of all applicable Nomograms and established operating limits and procedures.

DP 6.2 ISO Controlled Facilities

DP 6.2.1 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.

DP 6.2.2 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.

DP 6.2.3 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.

DP 6.3 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 the OCP, 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.

DP 6.4 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.

DP 6.5 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.

DP 6.6 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.

DP 6.7 Operating Voltage Control Equipment

DP 6.7.1 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.

DP 6.7.2 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.

DP 6.7.3 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.

DP 6.8 Outages

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 the OCP.

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 the OCP.

DP 6.9 Security Monitoring

The ISO shall be the Reliability Coordinator for the California Area. 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.

DP 6.9.1 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.

DP 6.9.2 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.

DP 7 REAL-TIME OPERATIONAL ACTIVITIES – THE HOUR PRIOR TO THE SETTLEMENT PERIOD

DP 7.1 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 SC'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.

DP 7.2 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 SBP and the SP 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.

DP 7.3 Supplemental Energy Bids

Supplemental Energy bids may be submitted to the ISO no later than sixty (60) minutes prior to the beginning of the Settlement Period in accordance with the format and content requirements of the SBP. These Supplemental Energy bids cannot be withdrawn after sixty (60) minutes prior to the beginning of the Settlement Period, except that a bid from a System Resource may specify that any portion of the bid that is not called prior to the beginning of the Settlement Period shall not be called after the beginning of the Settlement Period. The ISO may Dispatch the associated resource at any time during the Settlement Period.

DP 7.4 Intra-Zonal Congestion Management

In the hour prior to the beginning of the Settlement Period the ISO may adjust SCs' Final Schedules to alleviate Intra-Zonal Congestion. Except in those instances where the ISO calls Reliability Must-Run Units as provided in Section 5.2 of the ISO Tariff, the ISO will adjust resources in accordance with DP 8.4 and DP 8.5.

DP 8 REAL-TIME OPERATIONAL ACTIVITIES – THE SETTLEMENT PERIOD

DP 8.1 Settlement Period

DP 8.1.1 Responsibility of the ISO in Real-Time Dispatch

During real-time Dispatch, the ISO will be responsible for dispatching Generating Units, Curtailable Demands and Interconnection schedules to meet real-time imbalances between actual and scheduled Demand and Generation and to relieve Congestion, if necessary, to ensure System Reliability and to maintain Applicable Reliability Criteria.

DP 8.1.2 Utilization of BEEP

To achieve this, the ISO Control Center will utilize the merit order stack of available resources prepared pursuant to the SP through BEEP.

DP 8.2 Generating Units, Loads and Interconnection Schedules Dispatched for Congestion

If there is Inter-Zonal Congestion in real time, the ISO will use the merit order stack produced by BEEP to alleviate Inter-Zonal Congestion as described in DP 8.3. The ISO will manage Intra-Zonal Congestion in real time as set forth in Section 7.2.6.

DP 8.3 Inter-Zonal Congestion

DP 8.3.1 Treatment by Zone

If there is Inter-Zonal Congestion in real time, the ISO shall increase Generation and/or reduce Demand separately for each Zone.

DP 8.3.2 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 from the merit order stack 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.

DP 8.3.3 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 from the merit order stack the Generating Unit within the Zone with a non-zero capacity remaining to decrement which has the highest decremental bid price.

DP 8.4 Intra-Zonal Congestion

Except as provided in Section 5.2 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 Section 7.2.6.

DP 8.5 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 SBP 3.3. With respect to facilities financed with Local Furnishing Bonds the ISO shall adjust Final Schedules in real time in a fashion consistent with Section 2.1.3 and 7.1.6.3 of the ISO Tariff, Appendix B of the TCA, and Operating Procedures governing the use of such facilities.

DP 8.6 Real-Time Dispatch Application

DP 8.6.1 Real-Time Dispatch

During real time, the ISO shall dispatch Generating Units, Curtailable Demands and Interconnection schedules to meet imbalances between actual and scheduled Demand and Generation.

In addition, the ISO may need to purchase additional Ancillary Services if Ancillary Services arranged in advance are used to provide balancing Energy, and such depletion needs to be recovered to meet System Reliability contingency requirements.

DP 8.6.2 Utilization of the Merit Order Stack

The ISO will use the merit order stack as produced by BEEP, consisting of all the Supplemental Energy and Ancillary Services Energy bids as described in the SP 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 mid-point of 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.

DP 8.6.3 Basis for Real-Time Dispatch

The ISO shall base real-time Dispatch of Generating Units, Curtailable Demands and Interconnection schedules on the following principles:

(a) the ISO shall dispatch Generating Units and Interconnection schedules providing Regulation service to meet WECC and NERC Area Control Error (ACE) performance criteria;

(b) following the loss of a resource and once ACE has returned to zero, the ISO shall determine if the Regulation Generating Units and Interconnection schedules are operating at a point away from their Set Point. The ISO shall then adjust the output of Generating Units and Interconnection schedules (either providing Spinning Reserve, Non-Spinning Reserve or Supplemental Energy) to return the Regulation Generating Units and Interconnection schedules to their Set Points to restore their full regulating margin;

(c) the ISO shall dispatch Generating Units, Curtailable Demands and Interconnection schedules only to meet its balancing Energy requirements. The ISO shall not dispatch such resources in real time for economic trades either between SCs or within a SC's portfolio;

(d) the ISO shall select the Generating Units, Curtailable Demands and Interconnection schedules to be dispatched to meet its balancing Energy requirements based on the merit order stack of Energy bid prices produced by BEEP;

(e) the ISO shall not discriminate between Generating Units, Curtailable Demands and Interconnection schedules other than based on price, and the effectiveness (location and ramp rate) of the resource concerned to respond to the fluctuation in Demand or Generation;

(f) Generating Units, Curtailable Demands or Interconnection schedules shall be dispatched during the Settlement Period only until the next variation in Generation or Demand or the end of the Settlement Period, whichever is sooner. In dispatching such resources, the ISO is not making any commitment beyond the Settlement Period, as to the duration of their operation, nor the level of their output or Demand;

(g) The ISO will not differentiate between Ancillary Services procured by the ISO and Ancillary Services which are being self-provided;

(h) Within BEEP, once a decremental bid has been used by the ISO, it will then be included in the incremental part of the database with its incremental bid equal to its decremental price bid. Once an incremental bid has been used by the ISO it will then be included in the decremental part of the database with a decremental bid equal to its incremental price. In the event that the ISO subsequently needs to decrement output, it will initially decrement the Generating Units or Interconnection schedules incremented previously, and then continue down the merit order of the decremental bids; and

(i) The bid ramp rate of a resource will be considered by the BEEP Software in determining the amount of Instructed Imbalance Energy by BEEP Interval, and such consideration may result in Instructed Imbalance Energy in BEEP Intervals subsequent to the BEEP Interval to which the Dispatch instruction applies.

DP 8.7 Ancillary Services Requirements

The following requirements apply to the Dispatch of Ancillary Services in real time:

DP 8.7.1 Regulation

(a) Regulation provided from Generating Units or System Resources must meet the standards specified in the ASRP;

(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 DP 8.7.4);

DP 8.7.2 Operating Reserve

(a) Spinning Reserve:

(i) Spinning Reserve provided from Generating Units and Interconnection schedules must meet the standards specified in the ASRP;

(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 BEEP;

(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 the ASRP;

(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 BEEP; 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;

DP 8.7.3 Replacement Reserve

(a) Replacement Reserve provided from Generating Units, Curtailable Demands and Interconnection schedules must meet the standards specified in the ASRP;

(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 BEEP;

DP 8.7.4 Replacement of Operating Reserve

(a) in the event of an unforecasted 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 BEEP; and

(e) if the ISO restores Operating Reserve through utilization of Replacement Reserve, the ISO is not required to replace the utilized Replacement Reserve;

DP 8.7.5 Voltage Support

(a) Voltage Support provided from Generating Units shall meet the standards specified in the ASRP;

(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 2.5.3.4 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 DP 8.7.5 (b) and (c), the ISO will reduce output of Participating Generators certified in accordance with the ASRP based on the merit order stack as determined by BEEP. 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.

DP 8.7.6 Black Start

(a) Black Start shall meet the standards specified for Black Start in the ASRP; and

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

DP 8.8 Real-Time Management of Overgeneration Conditions

In the event that Overgeneration conditions occur during real time, the ISO will direct the SCs to take the steps described in Section 2.3.4 of the ISO Tariff and SCs shall implement ISO directions without delay.

DP 9 DISPATCH INSTRUCTIONS

DP 9.1 ISO Dispatch Authority

DP 9.1.1 Range of ISO Authority

The ISO has full authority to:

(a) direct the physical operation of the ISO Controlled Grid, including (without limitation) circuit breakers, switches, voltage control equipment, protective relays, metering and Load Shedding equipment;

(b) commit Reliability Must-Run Generation, except that the ISO shall only commit Reliability Must-Run Generation for Ancillary Services capacity according to Section 5.2 of the Tariff;

(c) order a change in operating status of voltage control equipment;

(d) take required action to prevent against uncontrolled losses of load or Generation;

(e) control the output of Generating Units and Interconnection schedules scheduled to provide Ancillary Services or offering Supplemental Energy;

(f) dispatch Curtailable Demand which has been scheduled to provide Non-Spinning Reserve or Replacement Reserve; and

(g) require the operation of resources which are at the ISO's disposal in a System Emergency, as described in DP 10.

DP 9.1.2 Exercise of the ISO's Authority

The ISO will exercise its authority under DP 9.1.1 by issuing Dispatch Instructions to the relevant Participants using the relevant communications method described in DP 4.

DP 9.2 Participant Responsibilities

DP 9.2.1 Compliance with Dispatch Instructions

All Participants within the ISO Control Area and all dynamically scheduled System Resources shall comply fully and promptly with the ISO's Dispatch Instructions unless such operation would impair public health or safety. Shedding Load for a System Emergency does not constitute impairment to public health or safety.

DP 9.2.2 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 SC immediately. The relevant SC shall notify the ISO of the problem immediately.

DP 9.3 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) 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 the ASRP.

DP 9.4 Response Required by Generators to ISO Dispatch Instructions

DP 9.4.1 Action Required by Generators

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 and ASRP;

(c) meet the ramp rates required by ASRP for the Ancillary Service concerned;

(d) respond to Dispatch Instructions for Ancillary Services within the time periods required by ASRP except in a System Emergency, when DP 10 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 shut down of a Generating Unit, within the time frame stated in the Instruction.

DP 9.4.2 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.

DP 9.5 Failure to Comply with Dispatch Instructions

DP 9.5.1 Obligation to Comply

All entities 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 to the ISO's Dispatch Instructions in accordance with their terms. If a dispatched Generating Unit, Curtailable Demand or Interconnection schedule fails to respond to a Dispatch Instruction in accordance with its terms, the Generating Unit, Curtailable Demand or Interconnection schedule:

(a) shall be declared and labeled as non-conforming to the Dispatch Instruction;

(b) cannot be eligible to set the Hourly Ex Post Price.

DP 9.5.2 Sanctions

The ISO will develop additional mechanisms to deter Generating Units and Loads in other Control Areas from failing to respond at a particular time or adequately respond over a particular period of time to a Dispatch Instruction or failing to perform according to Dispatch Instructions, for example, reduction in payments to SCs or suspension of the SC's Ancillary Services certificate for the Generating Unit, Curtailable Demand or System Resource concerned.

DP 10 EMERGENCY OPERATIONS

DP 10.1 Notifications by ISO

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

DP 10.1.1 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.

DP 10.1.2 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.

DP 10.1.3 System Emergency

When, in the judgement 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.

DP 10.2 Management of System Emergencies

DP 10.2.1 Declaration of System Emergencies

The ISO shall, when it determines that a System Emergency exists, declare the existence of such System Emergency. A declaration of System Emergency by the ISO shall be binding on all Participants until the ISO announces that the System Emergency no longer exists.

DP 10.2.2 Emergency Procedures

In the event of a System Emergency, the ISO shall:

(a) take action as it considers necessary to preserve or restore stable operation of the ISO Controlled Grid;

(b) act in accordance with Good Utility Practice to preserve or restore reliable, safe and efficient service as quickly as reasonably practicable;

(c) keep adjacent Control Area Operators informed as to the nature and extent of the System Emergency in accordance with WECC procedures; and

(d) where practicable, keep the Participants within the ISO Control Area informed.

DP 10.2.3 Intervention in Market Operations

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

(b) 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.

(c) Before any such intervention, the ISO must (in the following order):

(i) Dispatch all scheduled Generation and all other Generation offered or available to it, regardless of price (including all Supplemental Energy bids, and Ancillary Services);

(ii) Dispatch all interruptible Loads made available by UDCs to the ISO in accordance with the UDC Operating Agreements;

(iii) Dispatch or curtail all price-responsive Curtailable Demand that has been bid into any of the markets and exercise its rights under all Load curtailment contracts available to it; and

(iv) exercise Load Shedding to curtail Demand on an involuntary basis to the extent that the ISO considers necessary.

(d) The Administrative Price in relation to each of the markets for Imbalance Energy, Ancillary Services and Congestion Management shall be set at the applicable Market Clearing Price or appropriate charge, as the case may be, in the Settlement Period immediately preceding the Settlement Period in which the intervention took place.

(e) The intervention will cease as soon as the ISO has restored all Demand that was curtailed on an involuntary basis as specified in (c).

DP 10.2.4 Emergency Guidelines

The ISO shall issue procedures for all Participants to follow during a System Emergency. These guidelines shall be consistent with the specific obligations of SCs and Participants referred to in DP 10.2.8, and DP 10.4

DP 10.2.5 Implementation of Dispatch Instructions

All Participants shall respond to ISO Dispatch Instructions with an immediate response during System Emergencies.

DP 10.2.6 Periodic Tests of Emergency Procedures

The ISO shall develop and administer periodic unannounced tests of System Emergency procedures. The purpose of such tests will be to ensure that the Participants are capable of responding to actual System Emergencies.

DP 10.2.7 Prioritized Schedule for Shedding and Restoring Load

The ISO shall, in consultation with Participants, develop a prioritized schedule for Load Shedding if a System Emergency requires such action. Such a schedule will include a prioritization of restoring Load if multiple Participants are affected.

DP 10.2.8 Obligations of Participating Generators Relating to System Emergencies

All Generating Units are subject to control by the ISO during a System Emergency. The ISO shall have the authority to:

(a) instruct a Participating Generator to shut down any of its Generating Units which the Participating Generator does not require, or start any of its Generating Units that can be started in time to assist with the System Emergency;

(b) instruct a Participating Generator to increase or curtail the output of any of its Generating Units; and

(c) instruct the alteration of scheduled deliveries of Energy and/or Ancillary Services into or out of the ISO Controlled Grid,

if such an instruction is reasonably necessary to prevent an imminent System Emergency or to retain Operational Control over the ISO Controlled Grid during an actual System Emergency**,** and provided that the ISO has, where reasonably practicable, utilized Ancillary Services which it has the contractual right to instruct and which are capable of contributing to or containing or correcting actual, imminent or threatened System Emergencies prior to issuing such instructions.

DP 10.3 External Support/Assistance

If, on a real-time basis, the ISO is unable to comply with the Applicable Reliability Criteria, the ISO shall take such steps as it considers necessary, to ensure compliance, including the negotiation of contracts for Ancillary Services through processes other than competitive solicitations. If the ISO is unable to obtain such resources from within the ISO Controlled Grid, the ISO may solicit Ancillary Services from other Control Areas on a real-time basis.

DP 10.4 UDC Emergency Procedures

In the event of a System Emergency, each UDC shall comply with all directions from the ISO concerning the management and alleviation of the System Emergency and shall comply with all procedures outlined in this Protocol.

DP 10.4.1 Use of UDC's Existing Load Curtailment Programs.

(a) UDC Electrical Emergency Plans

The ISO shall have the authority to implement a UDC's Electrical Emergency Plan in consultation with the UDC, when Energy reserve margins are forecast to be at the levels specified in the existing plan.

(b) UDC Under-Frequency Load Shedding Programs (UFLS):

The ISO shall:

(i) with the UDC, review that UDC's UFLS program periodically to ensure compliance with Applicable Reliability Criteria;

(ii) perform periodic audits of each UDC's UFLS to verify that the system is properly configured for each UDC; and

(iii) use reasonable endeavors to ensure that the total ISO UFLS is coordinated among the UDCs so that no UDC bears a disproportionate share of the total ISO UFLS program.

(c) UDC Disconnect Load

The ISO shall have the authority to direct a UDC 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.

(d) UDC Load Curtailment Programs

As an additional resource for maintaining reliability and managing System Emergencies, the ISO may notify UDCs when the conditions exist which require the UDCs to implement their Load curtailment programs. 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.

DP 10.4.2 Load Curtailment

A SC may specify that Load 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. 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.

DP 11 ALGORITHMS TO BE USED

The ISO shall develop dispatch algorithms for use by the ISO for dispatching Generating Units and Curtailable Demands in accordance with the ISO Tariff.

DP 12 INFORMATION MANAGEMENT

The ISO shall provide all Participants with non-discriminatory access to information concerning the status of the ISO Controlled Grid by posting such information on the WEnet, or other similar computer communications device, or by telephone or facsimile in the event of computer systems failure.

DP 13 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

ISO MARKET MONITORING & INFORMATION PROTOCOL

ISO MARKET MONITORING AND INFORMATION PROTOCOL

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ISO Market Monitoring and Information Protocol (MMIP)

MMIP 1 OBJECTIVES, DEFINITIONS, AND SCOPE

MMIP 1.1 Objectives

This Protocol (MMIP) 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 16.3 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.

MMIP 1.1.1 Means and Actions

This Protocol sets forth general means of data collection, analysis, decision-making, and formulation of corrective actions, that will be instituted or undertaken by the ISO Department of Market Analysis and ISO Market Surveillance Committee. It describes implementation mechanisms to be created by the ISO to serve these purposes.

MMIP 1.1.2 Reporting Requirements

This Protocol 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 of this Protocol 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.

MMIP 1.2 Definitions

MMIP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. References to a Section or Appendix are to a Section or an Appendix of the ISO Tariff. References to MMIP are to this Protocol or to the stated section, paragraph or appendix of this Protocol.

MMIP 1.2.2 Special Terms for This Protocol

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

"Department of Market Analysis (DMA)" means the unit established under MMIP 3.1.

"Rules of Conduct" has the same meaning as provided for in the Enforcement Protocol.

"Market Surveillance Committee (MSC)" means the committee established under MMIP 5.1.

"ISO Home Page" means the ISO internet home page at http://www.caiso.com or such other internet address as the ISO shall publish from time to time.

MMIP 1.2.3 Rules of Interpretation

MMIP 1.2.3.1 Unless the context otherwise requires, if the provisions of this Protocol conflict with the ISO Tariff and/or the Enforcement Protocol, the ISO Tariff and the Enforcement Protocol will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

MMIP 1.2.3.2 A reference in this Protocol 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.

MMIP 1.2.3.3 The captions and headings in this MMIP are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

MMIP 1.2.3.4 This Protocol shall be effective as of January 1, 1998. Any amendment to this Protocol shall be effective as of the date of such amendment, or as of the date such amendment is approved by FERC.

MMIP 1.3 Scope

MMIP 1.3.1 Scope of Application to Parties

The MMIP applies to:

MMIP 1.3.1.1 All ISO Market Participants;

MMIP 1.3.1.2 The ISO;

MMIP 1.3.1.3 The Market Surveillance Committee.

MMIP 1.3.2 Liability of 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.

MMIP 2 PRACTICES SUBJECT TO SCRUTINY

MMIP 2.1 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 2.1. Where appropriate, it will take such further action as it considers necessary under Section 2.3.

MMIP 2.1.1 Anomalous Market Behavior

Anomalous market behavior, which is defined as behavior that departs significantly from the normal behavior in competitive markets that do not require continuing regulation or as behavior leading to unusual or unexplained market outcomes. Evidence of such behavior may be derived from a number of circumstances, including:

MMIP 2.1.1.1 withholding of Generation capacity under circumstances in which it would normally be offered in a competitive market;

MMIP 2.1.1.2 unexplained or unusual redeclarations of availability by Generators;

MMIP 2.1.1.3 unusual trades or transactions;

MMIP 2.1.1.4 pricing and bidding patterns that are inconsistent with prevailing supply and demand conditions, *e.g.,* prices and bids that appear consistently excessive for or otherwise inconsistent with such conditions; and

MMIP 2.1.1.5 unusual activity or circumstances relating to imports from or exports to other markets or exchanges.

The Department of Market Analysis shall evaluate, on an ongoing basis, whether the continued or persistent presence of such circumstances indicates the presence of behavior that is designed to or has the potential to distort the operation and efficient functioning of a competitive market, *e.g.,* the strategic withholding and redeclaring of capacity, and whether it indicates the presence and exercise of market power or of other unacceptable practices.

MMIP 2.1.2 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.

MMIP 2.1.3 Gaming

"Gaming", or taking unfair advantage of the rules and procedures set forth in the ISO Tariffs, Protocols or Rules of Conduct, or of transmission Constraints in periods in which exist substantial Congestion, to the detriment of the efficiency of, and of consumers in, the ISO Markets. “Gaming” may also include taking undue advantage of other conditions that may affect the availability of transmission and generation capacity, such as Loop Flow, facility outages, level of hydropower output or seasonal limits on energy imports from out-of-state, or actions or behaviors that may otherwise render the system and the ISO Markets vulnerable to price manipulation to the detriment of their efficiency.

MMIP 2.1.4 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 which may be evident from anomalous market behavior monitored under MMIP 2.1.1 above, from evidence of gaming monitored under MMIP 2.1.3 above, or from other activities.

MMIP 2.1.5 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.

MMIP 2.2 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 2.3.

MMIP 2.2.1 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.

MMIP 2.3 Response Action by ISO

MMIP 2.3.1 Corrective Actions

Where the monitoring activities or any consequent investigations carried out by the Department of Market Analysis pursuant to MMIP 2 and MMIP 4 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 MMIP 4, 6, and 7 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.

MMIP 2.3.2 Further Actions

Where the monitoring activities of or any consequent investigations carried out by the Department of Market Analysis pursuant to MMIP 2.1 and 2.2 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 ISO may publicize such activities or behavior and its recommendations thereof, in whatever medium it believes most appropriate. 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.

MMIP 2.3.3 Response to Gaming Behavior

If evidence of "gaming" or taking undue advantage exists, as described in MMIP 2.1.4, the Department of Market Analysis shall review the “gaming” behavior and/or the relationship between system conditions and market behavior and pricing in order to assess the potential for and impact of such gaming behavior, with a view to taking appropriate action, if necessary, either with respect to structural changes, or to changes to the ISO Tariff, Protocols or Rules of Conduct, or to proscribe specific behavior by Market Participants, as provided for in the Enforcement Protocol. In carrying out such activities the Department of Market Analysis shall in appropriate circumstances seek the advice of the MSC on the merits of such actions.

MMIP 2.3.4 Adverse Effects of Transition Mechanisms

Should the monitoring and analysis conducted under MMIP 2.2.3 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:

MMIP 2.3.4.1 the use of direct bid caps as a mechanism to prevent or mitigate artificially high Market Clearing Prices caused by abuses of market power;

MMIP 2.3.4.2 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;

MMIP 2.3.4.3 calling upon Reliability Must-Run Units to operate; and to modify Reliability Must-Run Contracts;

MMIP 2.3.4.4 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 MMIP 2.3.4, 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.

MMIP 3 ISO DEPARTMENT OF MARKET ANALYSIS

MMIP 3.1 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 MMIP and the adherence to its objectives, as set forth in MMIP 1.1.

MMIP 3.2 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 MMIP. 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.

MMIP 3.3 Accountability and Responsibilities

MMIP 3.3.1 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 referred to in this Protocol, including matters pertaining to market monitoring, information development and dissemination and pertaining to generic or entity-specific investigations, corrective actions or enforcement.

MMIP 3.3.2 CEO and MSC

The ISO CEO and the MSC shall each have the independent authority to refer any of the matters referred to in MMIP 3.3.1 to the ISO Governing Board for approval of recommended actions.

MMIP 3.3.3 Chief Executive Officer (CEO)

MMIP 3.3.3.1 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 MMIP 3.3.3.2.

MMIP 3.3.3.2 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.

MMIP 3.3.4 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.

MMIP 3.3.5 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.

MMIP 4 SPECIFIC FUNCTIONS OF ISO DEPARTMENT OF MARKET ANALYSIS

MMIP 4.1 Information Gathering and Market Monitoring Indices for Evaluation

MMIP 4.1.1 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.

MMIP 4.1.2 Data Categories

To develop the information system set forth in MMIP 4.1.1, 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.

MMIP 4.1.3 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.

MMIP 4.2 Evaluation of Information

MMIP 4.2.1 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 MMIP 4.1.2 and 4.1.3, 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 Protocol, 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.

MMIP 4.2.2 Submission of Evaluation Results

The final results of the Department of Market Analysis's ongoing evaluations under MMIP 4.2.1 shall routinely and promptly be submitted to the ISO CEO and to the MSC for comment.

MMIP 4.3 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.

MMIP 4.4 Reports and Recommendations

MMIP 4.4.1 ISO CEO and Governing Board

On the basis of the evaluation conducted under MMIP 4.2 or the review conducted under MMIP 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.

MMIP 4.4.2 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.

MMIP 4.4.3 ISO Market Surveillance Committee

All reports and recommendations to be made to regulatory agencies under MMIP 4.4.2, 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.

MMIP 4.5 Market Participants

MMIP 4.5.1 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 the Enforcement Protocol. 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.

MMIP 4.5.2 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.

MMIP 4.6 External Consulting Assistance and Expert Advice

In carrying out any of its responsibilities under this MMIP 4, 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 under MMIP 4.3, 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.

MMIP 4.7 Liability for Damages

As provided in Section 14.1 and 14.2 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 Protocol.

MMIP 5 MARKET SURVEILLANCE COMMITTEE

MMIP 5.1 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 as described in this Protocol 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.

MMIP 5.2 Composition

MMIP 5.2.1 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:

MMIP 5.2.1.1 economics, with emphasis on antitrust, competition, and market power issues in the electricity industry;

MMIP 5.2.1.2 experience in operational aspects of Generation and transmission in electricity markets;

MMIP 5.2.1.3 experience in antitrust or competition law in regulated industries; and

MMIP 5.2.1.4 financial expertise relevant to energy or other commodity trading.

MMIP 5.2.2 Criteria for Independence

Each member of the MSC must meet the following criteria for independence:

MMIP 5.2.2.1 no material affiliation, through employment, consulting or otherwise, with any Market Participant or Affiliate thereof consistent with the pertinent FERC Standards of Conduct; and

MMIP 5.2.2.2 no material financial interest in any Market Participant or Affiliate thereof consistent with the pertinent FERC Standards of Conduct.

MMIP 5.2.2.3 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).

MMIP 5.3 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 MMIP 5.2.1 and with the criteria for independence set forth in MMIP 5.2.2. 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 in accordance with this MMIP.

MMIP 5.4 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 MMIP 5.

MMIP 5.5 Liability for Damages

As provided in Section 14.1 and 14.2 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 Protocol.

MMIP 6 SPECIFIC FUNCTIONS OF MARKET SURVEILLANCE COMMITTEE (MSC)

MMIP 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 MMIP 4 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.

MMIP 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.

MMIP 6.3 Reports and Recommendations

MMIP 6.3.1 Required Reports

All evaluations carried out by the MSC pursuant to MMIP 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.

MMIP 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 Protocol, 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.

MMIP 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.

MMIP 7 IMPLEMENTATION OF RECOMMENDATIONS

MMIP 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 any ISO Protocol or Agreement or to any Rules of Conduct applicable in accordance with MMIP 9.

MMIP 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 MMIP 9.

MMIP 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; 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.

MMIP 8 PUBLICATION OF INFORMATION

MMIP 8.1 Market Monitoring Data and Indices

The ISO Department of Market Analysis shall, pursuant to MMIP 4.1, 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.

MMIP 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.

MMIP 9 AMENDMENTS

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

APPENDIX A

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.

1.2 CONDUCT WARRANTING MITIGATION

2.1 Definitions

The following definitions are applicable to this Appendix 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 BEEP 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 BEEP Interval and System Resources shall be the simple average of the six BEEP 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 BEEP stack: 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 (Pmin) and maximum (Pmax) 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 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 monthly changes in fuel prices using the proxy figure for natural gas prices posted on the ISO Home Page. Accepted and justified bids above the applicable soft cap, as set forth in Section 28.1.2 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 BEEP Stack: 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 BEEP 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 BEEP 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 BEEP Interval Ex Post Price. Bids mitigated in accordance with this Section 3.2.2.2 shall not set the BEEP 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 BEEP stack in the hours in which all Zonal BEEP Interval Ex Post Prices are projected to be below $91.87/MWh. If the Zonal BEEP 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 2.3.3.9.5 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.

OUTAGE COORDINATION PROTOCOL

OUTAGE COORDINATION PROTOCOL

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OUTAGE COORDINATION PROTOCOL (OCP)

OCP 1 OBJECTIVES, DEFINITIONS, AND SCOPE

OCP 1.1 Objectives

The objective of the OCP is to enable the ISO to coordinate maintenance outages as far as possible in advance to allow the ISO to maintain System Reliability and to minimize the quantity and effect of Congestion on the ISO Controlled Grid and Interconnections.

OCP 1.1.1 The Role of the ISO

The ISO Tariff authorizes the ISO to coordinate outage schedules for maintenance, repair and construction of Generating Units, sections of the ISO Controlled Grid, and Interconnections. This Protocol is designed to enable the ISO to perform this role.

The Facility Owner shall remain solely and directly responsible for the performance of all maintenance work, whether on energized or deenergized facilities, including all activities related to providing a safe working environment.

OCP 1.1.2 ISO Outage Coordination Office

The ISO Outage Coordination Office will be operational Monday through Friday, except holidays, and will accept, schedule, and approve or deny Maintenance Outage requests as necessary for the reliable operation of the ISO Controlled Grid. 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.

OCP 1.2 Definitions

OCP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix refers to a Section or an Appendix of the ISO Tariff unless otherwise indicated. References to OCP are to this Protocol or to the stated paragraph of this Protocol.

OCP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following words and expressions shall have the meaning set opposite them:

"Final Approval" means a statement of consent by the ISO Control Center to initiate a scheduled Outage.

OCP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) Unless the context otherwise requires, if the provisions of this Protocol and that of an existing contract conflict, the existing contract will prevail to the extent of the inconsistency.

(c) A reference in this Protocol 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.

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

(e) This Protocol shall be effective as of the ISO Operations Date.

(f) The Operating Procedures referenced in this Protocol, as may be amended from time to time, shall be posted on the ISO Home Page and such references in this Protocol shall be to the Operating Procedures then posted on the ISO Home Page.

OCP 1.3 Scope

OCP 1.3.1 Scope of Application to Parties

OCP applies to the ISO and to the following:

(a) Operators;

(b) Participating Generators;

(c) Connected Entities, to the extent the agreement between the Connected Entity and the ISO so provides; and

(d) Utility Distribution Companies (UDCs).

OCP 1.3.2 [Not Used]

OCP 1.3.3 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.

OCP 1.3.4 CALIFORNIA DEPARTMENT OF WATER RESOURCES

Outages of hydroelectric Generating Units owned and operated by the California Department of Water Resources shall not be subject to approval or change by the ISO. However, the California Department of Water Resources must comply with all applicable notification and reporting requirements under this Protocol and Section 2.3.3 of the ISO Tariff.

OCP 2 PLANNING OF GENERATING UNIT OUTAGES

OCP 2.1 Reporting for Regulatory Must-Take Generation

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.

OCP 2.2 Data to ISO

All information submitted in relation to planned Generating Unit Outages must be submitted in accordance with OCP 7.

OCP 2.2.1 Long-Range Planning Program

By October 15 of each year, each Generator will provide the ISO in writing with a proposed Outage schedule for each of its Generating Units (including its Reliability Must-Run Units) and System Units for the following calendar year. The following information is required for each Generating Unit:

(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.

OCP 2.2.1.1 Additional Maintenance Outages

If conditions require, a Participating Generator 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 affecting any of its units. The Participating Generator shall supply to the ISO the data set out in OCP 2.2.1 and applicable ISO Operating Procedures as posted on the ISO Home Page.

OCP 2.2.2 Quarterly Updates to Planned Generator Outage Program

Each Participating Generator will provide the ISO with quarterly updates of its long-range Outage schedule referred to in OCP 2.2.1 for Generating Units and System Units by the close of business on the fifteenth (15^{th}) 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.

OCP 2.2.3 Changes to Generator Outage Program

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.

Participating Generators must obtain the approval of the ISO Outage Coordination Office in accordance with OCP 4 and Section 2.3.3 of the ISO Tariff. Such approval may be withheld only for reasons of System Reliability or security.

OCP 2.2.4 Changes to Planned Maintenance Outages

A Participating Generator may submit changes to its planned Maintenance Outage schedule at any time. Changes must be approved by the ISO Outage Coordination Office. Such approval may be withheld only for reasons of System Reliability or security.

OCP 2.2.5 Additional Information Requests

The ISO may request additional information or seek clarification from Participating Generators of the information submitted in relation to a planned Generating Unit and System Unit Outage. This information may be used to assist the ISO in prioritizing conflicting requests for Outages.

(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.

OCP 2.3.2 System Adequacy Reports

The ISO will publish the following reports comparing the projected aggregate Generation capacity to the peak forecast Demands, as calculated in accordance with the Demand Forecast Protocol (DFP):

(a) on an annual basis and within eight weeks after receiving the annual or updated long-range planned Outage schedules from all Participating Generators, the ISO shall publish on the ISO Home Page a report comparing the aggregated weekly peak Generation capacity to the weekly peak forecast Demand for the next 52 weeks;

(b) on a quarterly basis, the ISO shall publish on the ISO Home Page a report comparing the aggregated weekly peak Generation capacity to the weekly peak forecast Demand for the next 3 months; and

(c) on a monthly basis, the ISO shall publish on the ISO Home Page a report comparing the aggregated weekly peak Generation capacity to the weekly peak forecast Demand for the next month.

OCP 2.3.3 Approval of Generation Outages

The information relating to each Maintenance Outage submitted by a Participating Generator in accordance with OCP 2.2 constitutes a request for a long-range Maintenance Outage and is not considered an Approved Maintenance Outage until the ISO has notified that Participating Generator of such approval pursuant to OCP 4.3.

OCP 3 PLANNING OF ISO CONTROLLED GRID MAINTENANCE

OCP 3.1 Data to ISO

All information submitted in relation to planned Outages of ISO Controlled Grid facilities must be submitted in accordance with OCP 7.

OCP 3.1.1 Long-Range Program

By October 15 of each year, each Participating TO will provide the ISO in writing with its list of proposed Maintenance Outages for the next calendar year. This list shall include the following data:

(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.

OCP 3.1.1.1 Additional Maintenance Outages

If conditions require, a Participating TO may, upon seventy-two (72) hours advance notice (or as specified in the Operating Procedures on the ISO Home Page), schedule with the ISO Outage Coordination Office a Maintenance Outage on its system. The Participating TO shall supply to the ISO the data set out in OCP 3.1.1.

OCP 3.1.2 Quarterly Update

Each Participating TO will provide the ISO with quarterly updates of the data provided under OCP 3.1.1 by close of business on the fifteenth (15^{th}) 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.

OCP 3.1.3 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.

OCP 3.1.4 Nature of Maintenance Outage Information

The information relating to each Maintenance Outage submitted by a Participating TO in accordance with OCP 3.1 constitutes a request for a long-range Maintenance Outage and is not considered an Approved Maintenance Outage until the ISO has notified the Participating TO of such approval pursuant to OCP 5.4.

OCP 3.1.5 Additional Information

The ISO may request additional information or seek clarification from Participating TOs of the information submitted in relation to a planned Maintenance Outage. This information may be used to assist the ISO in prioritizing conflicting requests for Outages.

OCP 3.1.6 Adjacent Control Areas

The ISO will coordinate the exchange of proposed ISO Controlled Grid Maintenance Outages, as appropriate, with the operators of adjacent Control Areas.

OCP 3.2 ISO Analysis of ISO Controlled Grid Outage Plans

OCP 3.2.1 Review of Planned Maintenance Outages

The ISO Outage Coordination Office will review the Maintenance Outages submitted under OCP 2.2 and OCP 3.1 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.

If in the ISO's determination, any of the proposed Maintenance Outages would cause the ISO to violate the Applicable Reliability Criteria, the ISO will notify the relevant Operator. The Operator then will revise the proposed Maintenance Outage and inform the ISO of the changes pursuant to OCP 2.2 and 3.1.

OCP 3.2.2 Suggested Amendments by the ISO

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 2.3.3.6 of the ISO Tariff.

OCP 3.2.3 Direction by the ISO

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 ISO will compensate the applicable Participating TO or Participating Generator, pursuant to the provisions of Section 2.3.3.6.3 of the ISO Tariff, for the direct and verifiable costs incurred by that Participating TO or Participating Generator as a result of the ISO's cancellation of an Approved Maintenance Outage. The Operator, acting in accordance with Good Utility Practice, shall comply with the ISO's direction. 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.

OCP 4 SCHEDULING AND APPROVAL OF GENERATOR MAINTENANCE OUTAGES

OCP 4.1 Regulatory Must-Take Generation

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. The Participating TO or UDC will advise the ISO Outage Coordination Office of scheduled and approved Maintenance Outages on resources providing Regulatory Must-Take Generation pursuant to existing contracts. If the Regulatory Must-Take Generator has executed a Participating Generator Agreement, it shall comply with OCP 2 and other provisions applicable to Participating Generators.

OCP 4.2 Schedule Confirmation and Final Approval of Scheduled Outages Required Under the ISO Tariff

Each Participating Generator which has scheduled a planned Maintenance Outage pursuant to OCP 2 must schedule and receive approval of the Outage from the ISO Outage Coordination Office in accordance with OCP 4 prior to initiating the Approved Maintenance Outage.

Under no circumstance shall an Operator start any Approved Maintenance Outage without receiving Final Approval from the ISO Control Center being requested and given in accordance with OCP 4.3.8.

OCP 4.3 Generator Outage Scheduling and Approval

OCP 4.3.1 Data Required

The Operator of a Participating Generator owned or controlled by a Participating Generator shall submit to the ISO pursuant to OCP 7 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). Such schedule confirmation request shall specify the following:

(a) the Generating Unit or System Unit name and Location Code;

(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;

(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.

OCP 4.3.2 Delay

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 OCP 4.3.1.

OCP 4.3.3 Acceptance or Rejection of Outage Schedule

The ISO Outage Coordination Office shall acknowledge receipt of each request to confirm or approve a Maintenance Outage for a Generating Unit, System Unit or Aggregated Unit and approve or reject such request in accordance with the Operating Procedures posted on the ISO Home Page.

OCP 4.3.4 Withdrawal or Modification of Request

The Operator of a Participating Generator may withdraw a request at any time prior to actual commencement of the Outage. The Operator of a Participating Generator 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 OCP 4.3.1, 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.

OCP 4.3.5 Rejection Notice

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.

OCP 4.3.6 Approval Mandatory

The Operator of a Participating Generator shall not initiate a Generating Unit Outage without receiving Final Approval as prescribed in OCP 4.3.8.

OCP 4.3.7 Priority of Participating Generator 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.

OCP 4.3.8 Final ISO Approval

On the day when an Approved Maintenance Outage is scheduled to commence the relevant Operator shall contact the ISO Control Center for Final Approval of the requested Outage including the starting time and return time. No such Outage shall commence without such Final Approval being obtained from the ISO Control Center, whose decision shall be final.

OCP 4.3.9 Withholding of Final Approval and Rescheduling of Outage

The ISO Control Center shall have the authority to withhold a Final Approval for an Approved Maintenance Outage for reasons of System Reliability. The ISO Control Center shall immediately notify the relevant Operator of its intention to withhold the Final Approval. The Generator Maintenance Outage will then be rescheduled pursuant to the Outage Coordination Protocol and Dispatch Protocol.

OCP 4.4 [Not Used]

OCP 4.4.1 [Not Used]

OCP 4.4.2 [Not Used]

OCP 4.4.3 [Not Used]

OCP 4.4.4 [Not Used]

OCP 4.4.5 [Not Used]

OCP 4.4.6 [Not Used]

OCP 4.4.7 [Not Used]

OCP 4.4.8 [Not Used]

OCP 4.4.9 [Not Used]

OCP 4.4.10 [Not Used]

OCP 5 ISO Controlled Grid Maintenance Scheduling and Approval

OCP 5.1 Schedule Confirmation and Final Approval of Scheduled Outages Required Under the ISO Tariff

Each Participating TO which has scheduled a Maintenance Outage pursuant to OCP 3 must schedule and receive approval of the Outage from the ISO Outage Coordination Office in accordance with OCP 5.4 prior to initiating the Approved Maintenance Outage.

Under no circumstance shall an Operator start any Approved Maintenance Outage without Final Approval from the ISO Control Center. Such Final Approval shall be requested and given in accordance with OCP 5.7.

OCP 5.2 Adjacent Control Areas

The ISO will coordinate the scheduling of ISO Controlled Grid facilities and approvals, as necessary, with the operators of adjacent Control Areas.

OCP 5.3 Data Required

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 OCP 5.3.1 and OCP 5.3.2.

A request to confirm a planned Maintenance Outage or to change an Approved Maintenance Outage shall specify:

(a) 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 Maintenance Outage is to begin;

(d) the date and time the Maintenance Outage is to be completed;

(e) the time required to terminate the maintenance and restore 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.

OCP 5.3.1 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). OCP 5.3.1 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.

OCP 5.3.2 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.

OCP 5.3.3 Priority of Transmission Facility Outage Requests

Outage requests which are listed in the long-range planned maintenance schedule submitted to the ISO will be given a priority in scheduling and approval of Outage requests over those which have not been listed.

OCP 5.3.4 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 OCP 5.3.1 and 5.3.2.

OCP 5.4 Acceptance or Rejection of Outage Schedule

The ISO Outage Coordination Office shall acknowledge receipt of each request to confirm or approve a Maintenance Outage for ISO Controlled Grid facilities and approve or reject such request in accordance with the Operating Procedures posted on the ISO Home Page.

OCP 5.5 Withdrawal or Modification of Request

A Participating TO's Operator may withdraw a request at any time prior to actual initiation of the Outage. A 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 OCP 5.3.1 and 5.3.2, but the ISO Outage Coordination Office shall have the right to reject such modified request because of the complexity of the modifications proposed or insufficient time to assess the impact of such modifications.

OCP 5.6 Rejection Notice

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.

OCP 5.6.1 Failure to Meet Requirements

Any request to consider maintenance that does not meet the notification requirements contained in OCP 5.3.1 and 5.3.2 will be rejected without further consideration, unless OCP 6 applies.

OCP 5.7 Final Approval Mandatory

Under no circumstance shall any Outage be initiated for which an approval is required, under this Protocol without the relevant Operator receiving Final Approval of that Outage in accordance with OCP 5.8.

OCP 5.8 Final ISO Approval

On the day when an Approved Maintenance Outage is scheduled to commence the relevant Operator shall contact the ISO Control Center for Final Approval of the requested Outage including the starting time and return time. No such Outage shall commence without such Final Approval being obtained from the ISO Control Center, whose decision shall be final.

OCP 5.9 Withholding of Final Approval and Rescheduling of Outage

The ISO Control Center shall have the authority to withhold a Final Approval 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 ISO Controlled Grid facility Maintenance Outage will then be rescheduled in accordance with this Protocol.

OCP 6 MANAGEMENT OF FORCED OUTAGES OR IMMEDIATE NATURE MAINTENANCE

OCP 6.1 Immediate Forced Outage

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 restricting an operating Generating Unit or removing a transmission facility from service, shall communicate directly with the ISO Control Center as set forth in the emergency procedures of the Dispatch Protocol.

OCP 6.2 Imminent Forced Outage

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 OCP 4 and OCP 5 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.

OCP 7 Communication of Scheduled Maintenance Requests

OCP 7.1 Single Point of Contact

All communications concerning a Maintenance Outage request or a request to confirm or change an Approved Maintenance Outage shall be between the ISO and the designated single point of contact for each Operator. The Operator shall provide in its initial request the identification of the single point of contact along with primary and alternate means of communication. This identification will be confirmed in all communications with the ISO in relation to Outage requests, including any request to the ISO for confirmation, change or Final Approval of an Outage.

OCP 7.2 Method of Communications

The primary method of communication from an Operator to the ISO 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.).

OCP 7.3 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 pursuant to OCP 7.2.

OCP 7.4 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.

OCP 8 OUTAGE COORDINATION FOR NEW FACILITIES

OCP 8.1 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.

OCP 8.2 Types of Work Requiring Coordination

The types of work which the ISO will coordinate under OCP 8 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.

OCP 8.3 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 OCP 5. The ISO Outage Coordination Office will make this determination in coordination with the respective requesting Operator or Connected Entity.

OCP 8.4 Special Procedures for More Complex Work

OCP 8.4.1 Responsibility for Preparation

In cases to which OCP 8.3 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.

OCP 8.4.2 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.

OCP 8.4.3 Approval of the Procedure

Upon receipt of the procedure and drawings referred to in OCP 8.4.2, 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.

OCP 8.4.4 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 OCP 8.4.2 and 8.4.3.

OCP 8.4.5 Approval of Work Requiring Coordination

No work can begin pursuant to any approved procedure unless approved by the ISO Outage Coordination Office and only in accordance with OCP 4 and OCP 5.

OCP 9 RECORDS AND REPORTS

OCP 9.1 Records of Approved Maintenance Outages

The ISO Outage Coordination Office will maintain a record of each Approved Maintenance Outage as it is implemented. 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.

OCP 10 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

OUTAGE COORDINATION PROTOCOL

APPENDIX A

[Not Used]

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SCHEDULES AND BIDS PROTOCOL

SCHEDULES AND BIDS PROTOCOL

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SCHEDULES AND BIDS PROTOCOL (SBP)

SBP 1 OBJECTIVES, DEFINITIONS AND SCOPE

SBP 1.1 Objectives

The objectives of this Protocol are:

(a) to require the provision of scheduling data to enable the ISO to undertake its scheduling process as described in the ISO Tariff and in the Scheduling Protocol (SP) taking into account the exercise of Firm Tranmission Rights and rights under Existing Contracts for transmission service;

(b) to require the provision of Ancillary Services Schedules and bidding data required by the ISO to enable the ISO to conduct its Ancillary Services auction as described in the ISO Tariff and in the SP; and

(c) to specify the contents of Schedules and to specify in detail the bidding data referred to in the ISO Tariff. The scheduling process and timing of the submission of data referred to are set forth in the SP.

SBP 1.2 Definitions

SBP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is to a Section or an Appendix of the ISO Tariff unless otherwise specified. References to SBP are to this Protocol or to the stated paragraph of this Protocol.

SBP 1.2.2 [Not Used]

SBP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol 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 Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

(e) References to time are references to the prevailing Pacific Time.

SBP 1.3 Scope

SBP 1.3.1 Scope of Application to Parties

The SBP applies to the following entities:

(a) Scheduling Coordinators (SCs);

(b) Participating Transmission Owners (PTOs); and

(c) the Independent System Operator (ISO).

SBP 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.

SBP 2 SCHEDULES AND NOTIFICATIONS

SBP 2.1 Contents of Schedules and Adjustment Bid Data

SCs must comply with the ISO Data Templates and Validation Rules document, which contains the format for submission of Schedules and bid. Except as noted, each of the following data sections can be submitted up to seven (7) days in advance.

SBP 2.1.1 Generation Section of a Balanced Schedule and Adjustment Bid Data

The Generation section of a Balanced Schedule will include the following information for each Generating Unit:

(a) SC's ID code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) name of Generating Unit scheduled;

(d) type of Schedule: Preferred or Revised (refer to the SP for details);

(e) 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;

(f) contract reference number for Reliability Must-Run Generation;

(g) Congestion Management flag – "Yes" indicates that any Adjustment Bid submitted under item (k) below should be used;

(h) publish Adjustment Bid flag, which will not be functional on the ISO Operations Date. In the future, “Yes” will indicate that the SC wishes the ISO to publish its Adjustment Bids;

(j) Generating Unit ramp rate in MW/minute;

(j) 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); and

(k) the MW and $/MWh values for each Generating Unit for which an Adjustment Bid is being submitted consistent with SBP 4.

SBP 2.1.2 Demand Section of a Balanced Schedule and Adjustment Bid Data

The Demand section of a Balanced Schedule will include the following information for each Demand location:

(a) SC’s ID code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) Demand ID – Demand location (which must be the name of a Demand Zone, Load group or bus);

(d) type of Schedule: Preferred or Revised (refer to the SP for details);

(e) hourly scheduled MWh for each Settlement Period of the Trading Day that uses the Existing Contract indicated in (e) above (which values should be less than or equal to the values indicated in (i) below);

(f) Congestion Management flag – “Yes” indicates that any Adjustment Bid submitted for a Dispatchable Load under item (i) below should be used;

(g) publish Adjustment Bid flag, which will not be functional on the ISO Operations Date. In the future, “Yes” will indicate that the SC wishes the ISO to publish its Adjustment Bids;

(h) 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);

(i) the MW and $/MWh values for each Dispatchable Load for which an Adjustment Bid is being submitted consistent with SBP 4; and

(j) requisite NERC tagging data.

SBP 2.1.3 External Import/Export Section of a Balanced Schedule and Adjustment Bid Data

The external import/export section of a Balanced Schedule will include the following information for each import or export:

(a) SC's ID code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) Scheduling Point (the name);

(d) type of Schedule: Preferred or Revised (refer to the SP for details);

(e) interchange ID (the name of the selling entity, the buying entity, and a numeric identifier);

(f) Energy type – firm (FIRM), non-firm (NFRM) or dynamic (DYN) or Wheeling (WHEEL);

(g) external Control Area ID;

(h) 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);

(i) contract reference number for Reliability Must-Run Generation or Existing Contract (or set of interdependent Existing Contracts);

(j) contract type – transmission (TRNS), Energy (ENGY) or both (TR_EN);

(k) Schedule ID (NERC ID number);

(l) Congestion Management flag - "Yes" indicates that any Adjustment Bid submitted for an external import/export in item (q) below should be used;

(m) publish Adjustment Bid flag, which will not be functional on the ISO Operations Date. In the future, "Yes" will indicate that the SC wishes the ISO to publish its Adjustment Bids;

(n) complete WECC tag;

(o) 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; and

(p) the MW and $/MWh values for each external import/export for which an Adjustment Bid is being submitted consistent with SBP 4.

SBP 2.1.4 Inter-Scheduling Coordinator Energy Trades ("Internal Imports/Exports") Section of a Balanced Schedule

In the event of an Inter-Scheduling Coordinator Energy Trade, the SCs who are parties to that trade must agree on a Zone in which the trade will be deemed to take place ("Trading Zone") and notify the ISO accordingly. The purpose of designating a Trading 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:

(a) SC's ID code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) trading SC (buyer or seller);

(d) type of Schedule: Preferred or Revised (refer to the SP for details);

(e) Trading Zone;

(f) Schedule type – Energy (ENGY);

(g) 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 SC reported as negative quantities and internal exports from the SC reported as positive quantities;

(h) Congestion Management flag – "Yes" indicates that Adjustment Bid submitted under (k) below should be used;

(i) publish Adjustment Bid flag – "Yes" indicates that the SC wishes the ISO to publish its Adjustment Bid.

(j) the Generating Unit or Dispatchable Load that is the source or recipient of Energy traded; and

(k) the MW and $/MWh values for each Generating Unit or Dispatchable Load that is the source or recipient of Energy traded.

SBP 2.1.5 Inter-Scheduling Coordinator Ancillary Service Trades ("Internal Imports/Exports") Section of a Balanced Schedule

In the event of an Inter-Scheduling Coordinator Ancillary Service Trade, the SCs who are parties to that trade must agree on a Trading Zone in which the trade is deemed to take place and notify the ISO accordingly. The Ancillary Service obligations in the Trading 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) SC's ID code;

(b) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) Trading SC (buyer or seller);

(d) Trading 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.

SBP 2.1.6 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 the day prior to the Trading Day, as set forth in the timing requirements of the SP. 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:

(a) SC’s ID code:

(b) Type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(c) From Zone (must be different than “to Zone”), is the Zone in which all sources specified in the contract usage template must be located;

(d) To Zone (must be different than “from Zone”), is the Zone in which all sinks specified in the contract usage template must be located;

(e) 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");

(f) Usage ID (a unique identifier that allows a SC to submit multiple usages for a given Inter-Zonal Interface);

(g) 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;

(h) Priority usage, relative to all contract usages specified in a SC'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

(i) 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 SC is submitting the templates in accordance with SBP 7.2(a), or up to 20 combinations of sources and sinks if an SC is submitting the templates in accordance with SBP 7.2(b) or SBP 7.2(c));

(1) Type of resource – Generation (GEN), load (LOAD), interchange (INTRCHNGE) or inter-Scheduling Coordinator trade (INTER_SC);

(2) Resource_ID – generator_ID, load_ID, tie_point or trading SC;

(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.

SBP 2.1.7 No Scheduling Coordinator shall submit a Circular Schedule. The ISO may periodically provide examples of such Circular Schedules under the ISO Home Page.

SBP 2.2 Validation of Balanced Schedules

Each SC 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 SC 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 SC'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 SP) for submission of Schedules. However, a SC can also initiate the stage two validation at any time prior to that deadline, as described in more detail in the SP. If the SC adds a new Schedule or modifies an existing Schedule, that Schedule must be re-validated. SCs must comply with the ISO Data Templates and Validation Rules document, which contains the validation criteria for Balanced Schedules.

SBP 2.2.1 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 SC had not exceeded its Security Amount and verify that the SC is certified in accordance with the ISO Tariff. The ISO will further verify that the SC has inputted valid Generating Unit and Demand location identification. Scheduled Reliability Must-Run Generation will be verified against the contract reference numbers in the ISO's Scheduling Coordinator database. A technical validation will be performed verifying that a scheduled Generating *Unit's* output is not beyond it's declared capacity and/or operating limits. If there is an error found during stage one validation, the SC will be notified immediately through WEnet. The SC 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 timing requirements of the SP. 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 SC and allow the SC to view the message(s), to make changes, and to resubmit the contract usage template(s) if it is still within the timing requirements of the SP. The SC is also notified of successful validation via WEnet.

SBP 2.2.2 Stage Two Validation

During stage two validation, Schedules will be checked to determine whether each SC's aggregate Generation and external imports (adjusted for Transmission Losses) and Inter-Scheduling Coordinator Energy Trades (whether purchases or sales) equals the SC's aggregate Demand Forecast, including external exports. The SC must take into account the applicable Generation Meter Multipliers (GMMs) as described in the SP. The SC 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 SCs 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 SC. This validation is performed in accordance with the timing requirement described in the SP. An SC 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, as described in the SP, at any time prior to the deadline for submission of Preferred Schedules or Revised Schedules (as the case may be). It is the SC's responsibility to perform such checks, if desired. The SC 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 SC'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 SCs of the mismatch in Energy quantity and/or location. The SC 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 timing requirements of the SP. The SC is also notified of successful validation via WEnet.

SBP 2.3 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 sumbitted for a Generating Unit, applicable to a particular operating hour, should be physically achievable within the applicable operating hour.

SBP 3 EXISTING CONTRACTS FOR TRANSMISSION SERVICE

SBP 3.1 Application of SBP 3 to Rights under Existing Contracts

SBP 3.1.1 Existing Rights

The provisions of Sections 2.4.3 and 2.4.4 of the ISO Tariff shall, with respect to the exercise of Existing Rights following the ISO Operations

Date, be implemented in accordance with this SBP 3 and such other operational protocols as may be developed on a case by case basis pursuant to these sections. The objective of this SBP 3 is to properly treat Existing Rights in accordance with the ISO Tariff and to minimize the need for other operational protocols.

SBP 3.1.2 Converted Rights

This SBP 3 shall have no application to the exercise of Converted Rights other than as set forth in Section 2.4.4.3 of the ISO Tariff.

SBP 3.2 Responsible Participating Transmission Owners

For each Existing Contract, the party providing transmission service (the "Responsible PTO") shall be responsible for the submission of transmission rights/curtailment instructions ("instructions") to the ISO under this SBP on behalf of the holders of Existing Rights, unless the parties to the Existing Contract agree otherwise. For the purposes of this Protocol, such otherwise agreed party will be acting in the role of Responsible PTO. 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 PTO 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 PTO, the relevant PTOs will designate a single PTO as the Responsible PTO and will notify the ISO accordingly. If no such Responsible PTO is designated by the relevant PTOs or the ISO is not notified of such designation, the ISO shall designate one of them as the Responsible PTO and notify the relevant PTOs accordingly.

SBP 3.3 Instructions Defining Transmission Service Rights

SBP 3.3.1 Data Requirements

The Responsible PTO 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 SBP 3.3.5, the instructions that are necessary to implement the exercise of the Existing Rights in accordance with the ISO Tariff. These 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 Appendix to this Protocol (the "Transmission Rights/Curtailment Instructions Template"). 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 Appendix to this Protocol):

(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 SBP 3.4 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) SC ID code: the ID number of the SC 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 the SP;

(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 SC 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 SC 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 SBP 3.3.2. 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).

SBP 3.3.2 Curtailment under Emergency and Non-Emergency Conditions

SBP 3.3.2.1 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 SBP 3.3.1. 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.

SBP 3.3.2.2 Non-Emergency Conditions

Unless otherwise specified by the Responsible PTO in the instructions that it submits to the ISO under SBP 3.3.1, 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 the SBP 2.1.6 and in the SP.

SBP 3.3.3 [Not Used]

SBP 3.3.4 Instructions that cannot be Exercised Independent of the ISO's Day-to-Day Involvement

Those instructions that define the transmission rights within which uses may be scheduled or curtailed and that cannot be exercised independent of the ISO's day-to-day involvement must be submitted to the ISO in accordance with SBP 3.3.1. 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 SCs representing the holders of Existing Rights will submit their Schedules to the ISO for implementation in accordance with the instructions.

SBP 3.3.5 Timing of Submission of Instructions to ISO

SBP 3.3.5.1 Initial Submittal of Instructions

The Responsible PTOs shall submit 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 2.4.3 or 2.4.4 of the ISO Tariff.

SBP 3.3.5.2 Changes to Instructions

Updates or changes to the 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 to which the provisions of this SBP 3.3 will apply. 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.

SBP 3.4 Validation of Existing Contract Schedules

Each Schedule submitted to the ISO by a SC representing a rights holder to an Existing Contract must include a valid contract reference number in accordance with SBP 3.3. If the Schedule includes an Inter-Scheduling Coordinator Trade, only one of the SCs 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 SCs which are parties to an Inter-Scheduling Coordinator Trade submit contract reference numbers, the ISO will issue an error message to the SC via the WEnet (as described in SBP 2.2.1) and indicate the nature of the problem. The ISO will assist the SC, within reason, in resolving the problem so that the SC is able to submit the Schedule successfully as soon as possible within the timing requirements of the SP. If the SC 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 SC notified by the ISO's issuance of an invalidated usage information template.

SBP 4 ADJUSTMENT BIDS

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. These Adjustment Bids will not be transformed into Supplemental Energy bids. However, these Adjustment Bids are treated as standing offers to the ISO and may be used by the ISO in the Real Time Market for the purpose of managing Intra-Zonal Congestion using System Resources, Dispatchable Loads and increasing Generating Units' output for managing Overgeneration conditions.

SBP 4.1 Content of Adjustment Bids

Adjustment Bids are contained in Preferred Schedules and Revised Schedules submitted by SCs 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 SC is required to submit a preferred operating point for each Generating Unit, Dispatchable Load and external import/export (these quantities are presented in the SC's submitted Schedule as "Hourly MWh"). The SC'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.

SBP 4.2 Format of Adjustment Bids

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 SC's Balanced Schedule and must be related to each Generating Unit, Dispatchable Load and external import/export. SCs must comply with the ISO Data Templates and Validation Rules document, which contains the format for submission of Adjustment Bids.

SBP 4.3 Timing of Submission of Adjustment Bids

The specific timeline requirements for the submission of Adjustment Bids in both the Day-Ahead Market and the Hour-Ahead Market are described in the SP. 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 SC in its Revised Day-Ahead Schedule, if any.

SBP 4.4 Publication of Adjustment Bids

The ISO will publish Adjustment Bids in accordance with applicable provisions of the ISO Tariff governing the disclosure of bid data.

SBP 4.5 Validation of Adjustment Bids

SBP 4.5.1 Invalidation

The absence of an Adjustment Bid in a SC's Preferred Schedule or Revised Schedule will not affect the validation since SCs are not required to submit Adjustment Bids. If an Adjustment Bid is contained in the SC'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 SC 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 SC's notification screen which will specify the nature of the error. The SC 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 SC is also notified of successful validation via WEnet. The SCs must comply with the ISO Data Templates and Validation Rules document, which contains the validation criteria for Adjustment Bids.

SBP 4.5.2 Validation Checks

The ISO's stage one validation checks are performed automatically, whenever Schedules and Adjustment Bids are submitted, as described in the SP. The ISO's stage two validation is performed automatically in accordance with the timing requirements described in the SP. An SC 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, as described in the SP, at any time prior to the deadline for submission of Preferred Schedules or Revised Schedules. It is a SC's responsibility to perform such checks.

SBP 4.6 [NOT USED]

SBP 5 ANCILLARY SERVICES

SCs must comply with the ISO Data Templates and Validation Rules document, which contains the format for submission of Ancillary Services schedules and bids. Additionally, SCs should refer to the Ancillary Services bid evaluation and scheduling principles contained in the SP. As also described in the SP, the resources constituting a System Unit which submitted Ancillary Services bids or schedules and which, as a result, has been accepted by the ISO to supply Ancillary Services in a Settlement Period must be disclosed to the ISO one (1) hour prior to the start of the Settlement Period.

SBP 5.1 Content of Ancillary Services Schedules and Bids

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 SC wishes to submit Ancillary Services Schedules and bids must meet the requirements set forth in the Ancillary Services Requirements Protocol (ASRP). For each Ancillary Service offered to the ISO auction or self-provided, SCs must include a bid price for Energy in the form of a staircase function composed of up to eleven (11) ordered pairs (i.e., ten (10) steps or price bands) of quantity/price information. These staircase functions must be either monotonically non-decreasing (Generating Units, System Units, and System Resources) or monotonically non-increasing (Curtailable Demands). 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 SP). 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 as described in the SP. Each of the following data sections can be submitted up to seven (7) days in advance. 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.

SBP 5.1.1 Regulation

SBP 5.1.1.1 Regulation: Generating Units or System Units

Each SC desiring to self-provide Regulation or to participate in the ISO's Regulation auction will submit the following information for each relevant Generating Unit or System Unit for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Regulation Ancillary Service (ANC_SRVC) or Revised Regulation Ancillary Service (REVISED_ANC_SRVC);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Generating Unit or System Unit ID code;

(e) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(f) upward and downward range of Generating Unit or System Unit capacity over which the Generating Unit or System Unit is offering to provide Regulation;

(g) Generating Unit or System Unit operating limits (high and low MW);

(h) Generating Unit or System Unit ramp rate (MW/minute);

(i) bid price for Regulation capacity ($/MW); and

(j) bid price for regulating Energy if called upon ($/MWh) (required for validation bid only).

SBP 5.1.1.2 Regulation: External Imports

Each SC desiring to self-provide Regulation or 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) type of schedule: (Regulation Ancillary Service);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Scheduling Point (the name)

(e) interchange ID code (the name of the selling entity, buying entity and a numeric identifier);

(f) external Control Area ID;

(g) Schedule ID (NERC ID number);

(h) complete WECC tag;

(i) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(j) in the case of Existing contracts, the applicable contract reference number;

(k) upward and downward range of System Resource capacity over which the System Resource is offering to provide Regulation;

(l) System Resource operating limits (high and low MW);

(m) ramp rate (MW/minute);

(n) bid price for Regulation capacity ($/MW); and

(o) bid price for Regulation Energy if called upon ($/MWh).

SBP 5.1.2 Spinning Reserve

SBP 5.1.2.1 Spinning Reserve: Generating Units or System Units

Each SC desiring to self-provide Spinning Reserve or to participate in the ISO's Spinning Reserve auction will submit the following information for each relevant Generating Unit or System Unit for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Generating Unit or System Unit ID code;

(e) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(f) Generating Unit or System Unit operating limits (high and low MW);

(g) Spinning Reserve capacity (MW);

(h) Generating Unit or System Unit ramp rate (MW/minute);

(i) bid price for Spinning Reserve capacity ($/MW); and

(j) bid price for Spinning Reserve Energy if called upon ($/MWh).

SBP 5.1.2.2 Spinning Reserve: External Imports/Exports

Each SC desiring to bid or self-provide Spinning Reserve will submit the following information for each relevant external import for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Scheduling Point (the name);

(e) interchange ID code (the name of the selling entity, buying entity and a numeric identifier);

(f) external Control Area ID;

(g) Schedule ID (NERC ID number);

(h) complete WECC tag;

(i) preferred bid flag, which must be set to "NO", indicating a self-provided schedule, until such time as the ISO's scheduling system is able to support Ancillary Services bids from external imports/exports;

(j) export flag, a "YES" indicates an external export and a "NO" indicates an external import;

(k) In the case of Existing Contracts, the applicable contract reference number;

(l) Spinning Reserve capacity (MW);

(m) ramp rate (MW/minute); and

(n) bid price for Spinning Reserve Energy if called upon ($/MWh).

SBP 5.1.3 Non-Spinning Reserve

SBP 5.1.3.1 Non-Spinning Reserve: Generating Units or System Units

Each SC desiring to self-provide Non-Spinning Reserve or to participate in the ISO's Non-Spinning Reserve auction will submit the following information for each relevant Generating Unit or System Unit for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Non-Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Generating Unit or System Unit ID code;

(e) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(f) time to synchronize following notification (less than ten (10) minutes mandatory);

(g) Non-Spinning Reserve capacity available within ten (10) minutes following notification (MW);

(h) Generating Unit or System Unit operating limits (high and low MW);

(i) Generating Unit or System Unit ramp rate (MW/minute);

(j) bid price for Non-Spinning Reserve capacity ($/MW); and

(k) bid price for Non-Spinning Reserve Energy if called upon ($/MWh).

SBP 5.1.3.2 Non-Spinning Reserve: Curtailable Demands

Each SC desiring to self-provide Non-Spinning Reserve or to participate in the ISO's Non-Spinning Reserve auction will submit the following information for each relevant Curtailable Demand for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Non-Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);

(b) SC's ID code;

(c) type of market (Day-Ahead and Hour-Ahead) and Trading Day;

(d) available Curtailable Demand ID code;

(e) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(f) maximum allocation curtailment duration (hours) (CURT_HR);

(g) time to interruption following notification (minutes);

(h) amount of Curtailable Demand that can be interrupted within ten (10) minutes following notification (MW);

(i) bid price for Non-Spinning Reserve capacity ($/MW); and

(j) bid price for Non-Spinning Reserve Energy if called upon ($/MWh).

SBP 5.1.3.3 Non-Spinning Reserve: External Imports/Exports

Each SC desiring to bid or self-provide Non-Spinning Reserve will submit the following information for each relevant external import for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Non-Spinning Reserve Ancillary Service (ANC_SRVC) or Revised Non-Spinning Reserve Ancillary Service (REVISED_ANC_SRVC);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Scheduling Point (the name);

(e) interchange ID code (the name of the selling entity, buying entity and a numeric identifier);

(f) external Control Area ID;

(g) Schedule ID (NERC ID number);

(h) complete WECC tag;

(i) preferred bid flag, which must be set to "NO", indicating a self-provided schedule;

(j) export flag, a "YES" indicates an external export and a "NO" indicates an external import;

(k) In the case of Existing Contracts, the applicable contract reference number;

(l) time to synchronize following notification (less than ten (10) minutes mandatory);

(m) Non-Spinning Reserve capacity (MW);

(n) ramp rate (MW/minute); and

(o) bid price for Non-Spinning Reserve Energy if called upon ($/MWh).

SBP 5.1.4 Replacement Reserve

SBP 5.1.4.1 Replacement Reserve: Generating Units or System Units

Each SC desiring to self-provide Replacement Reserve or to participate in the ISO's Replacement Reserve auction will submit the following information for each relevant Generating Unit or System Unit for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Replacement Reserve Ancillary Service (ANC_SRVC) or Revised Replacement Reserve Ancillary Service (REVISED_ANC_SRVC);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Generating Unit or System Unit ID code;

(e) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(f) time to synchronize following notification (less than sixty (60) minutes mandatory);

(g) Generating Unit or System Unit operating limits (high and low MW);

(h) Replacement Reserve capacity available within sixty (60) minutes following notification (MW);

(i) Generating Unit or System Unit ramp rates (MW/minute);

(j) bid price for Replacement Reserve capacity ($/MW); and

(k) bid price for Replacement Reserve Energy if called upon ($/MWh).

SBP 5.1.4.2 Replacement Reserve: Curtailable Demands

Each SC desiring to self-provide Replacement Reserve or to participate in the ISO's Replacement Reserve auction will submit the following information for each relevant Curtailable Demand for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Replacement Reserve Ancillary Service (ANC_SRVC) or Revised Replacement Reserve Ancillary Service (REVISED_ANC_SRVC);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Curtailable Demand ID code;

(e) preferred bid flag, a "YES" indicates a bid and a "NO" indicates a self-provided schedule;

(f) maximum allocation curtailment duration (hours) (CURT_HR);

(g) time to reduction following notification (minutes);

(h) amount of Curtailable Demand that can be interrupted within sixty (60) minutes following notification (MW);

(i) Curtailable Demand reduction rate (MW/minute);

(j) bid price for Replacement Reserve capacity ($/MW); and

(k) bid price for Replacement Reserve Energy if called upon ($/MWh).

SBP 5.1.4.3 Replacement Reserve: External Imports

Each SC desiring to bid or self-provide Replacement Reserve will submit the following information for each relevant external import for each Settlement Period of the relevant Trading Day:

(a) type of schedule: Replacement Reserve Ancillary Service (ANC_SRVC) or Revised Replacement Reserve Ancillary Service (REVISED_ANC_SRVC);

(b) SC's ID code;

(c) type of market (Day-Ahead or Hour-Ahead) and Trading Day;

(d) Scheduling Point (the name);

(e) interchange ID code (the name of the selling entity, buying entity and a numeric identifier);

(f) external Control Area ID;

(g) Schedule ID (NERC ID number);

(h) complete WECC tag;

(i) preferred bid flag, which must be set to "NO", indicating a self-provided schedule, until such time as the ISO's scheduling system is able to support Ancillary Services bids from external imports;

(j) in the case of Existing Contracts, the applicable contract reference number;

(k) time to synchronize following notification (less than sixty (60) minutes mandatory);

(l) Replacement Reserve capacity (MW);

(m) ramp rate (MW/minute); and

(n) bid price for Replacement Reserve Energy if called upon ($/MWh).

SBP 5.2 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 SC notifying the SC of the errors in the Schedules and/or bids. SCs 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:

SBP 5.2.1 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 SC 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 SC's notification screen which will specify the nature of the error. The SC 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 SC is also notified of successful validation via WEnet.

SBP 5.2.2 Stage Two Validation

Stage two validation will be conducted by the ISO in accordance with Appendix E of the ISO Tariff.

SBP 5.2.3 Validation Checks

The ISO's stage one validation checks are performed automatically whenever Ancillary Services Schedules and bids are submitted, as described in the SP. The ISO's stage two validation is performed automatically in accordance with the timing requirements described in the SP. A SC 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 SC's responsibility to perform such checks.

SBP 5.3 Buy Back of Ancillary Services

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 such capacity to the extent scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or to the extent 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 Scheduing 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 at the Market Clearing Price in the Hour-Ahead Market for the same Settlement Period for the Ancillary Service capacity concerned.

SBP 6 SUPPLEMENTAL ENERGY BIDS

There is no requirement for SCs to submit Supplemental Energy bids. Supplemental Energy bids submitted, however, are available to the ISO for procurement and use for Imbalance Energy, additional Voltage Support and Congestion Management in the Real Time Market.

SBP 6.1 Content of Supplemental Energy Bids

SBP 6.1.1 Generation Section of Supplemental Energy Bid Data

Each SC offering Supplemental Energy to the ISO will submit the following information for each Generating Unit for each Settlement Period:

(a) SC's ID code;

(b) name of Generating Unit;

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

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

.

(e) the MW and $/Mwh values for each Generating Unit for which a Supplemental Energy bid is being submitted consistent with this SBP 6

A Physical Scheduling Plant shall be treated as a single Generating Unit for Supplemental Energy bid purposes.

SBP 6.1.2 Demand Section of Energy Bid Data

Each SC 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) SC's ID code;

(b) name of Demand;

(c) the MW and $/MWh values for each Demand for which a Supplemental Energy bid is being submitted consistent with this SBP 6.

SBP 6.1.3 External Import Section of Energy Bid Data

Each SC 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) SC'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) 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 SBP 6;
(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.

SBP 6.2 Format of Energy Bids

The SC's preferred operating point 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 a single ramp rate associated with the entire MW range. SCs must comply with the ISO Data Templates and Validation Rules document, which contains the format for submission of Supplemental Energy bids.

SBP 6.3 Timing of Submission of Supplemental Energy Bids

For specific timeline requirements for the submission of Supplemental Energy bids see the Dispatch Protocol.

SBP 6.4 Validation of Supplemental Energy Bids

The ISO will check whether Supplemental Energy bids comply with the format requirements and will notify a SC if its bid does not so comply. A SC can check whether its Supplemental Energy bids will pass the ISO's validation by manually initiating validation of its Supplemental Energy bids at any time prior to the deadline for submission of Supplemental Energy bids. It is the SC's responsibility to perform such checks. SCs must comply with the ISO Data Templates and Validation Rules document, which contains the validation criteria for Supplemental Energy bids.

SBP 7 INTERFACE REQUIREMENTS

SBP 7.1 WEnet

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).

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

SBP 7.2 Templates

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 SC's own API.

SBP 7.3 Public/Private Information

Through the use of the security provisions of WEnet, some data will be provided on a confidential basis (such as individual SC 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.

SBP 7.4 Individual SC Communication Failure

If there is a failure of communications with a SC, then, <u>at the ISO's discretion</u>, the SC may communicate by facsimile, but only if the ISO and the SC have communicated by telephone in advance.

SBP 7.5 Failure/Corruption of WEnet

Based on the designed reliability of the WEnet, there is no external back-up communications system. In the extremely unlikely event of WEnet failure, communications will be lost to <u>all</u> SCs and the ISO will use the latest valid information available to operate until restoration of WEnet.

SBP 8 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

SBP APPENDIX

TRANSMISSION RIGHTS/CURTAILMENT INSTRUCTIONS TEMPLATE

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): Path Name(s)	POR Zone	POD Zone	(f) Party	(g) SC ID	(h) ER/NCR	(i)(j) Types and Amounts of Transmission Service: Firm /1/	CF /1/	N-F	(k) DA (hour-ending)	(l) HA (minutes)	(m) RT (yes/no)	(n) Service Period: Beginning	Ending
[name/number 1]		[zone name]	[zone name]	[party 1]	[sc id 1]	[er]	[MW]	[MW]	[MW]	[1400]	[30]	[yes]	[hh/dd/mm/yy]	[hh/dd/mm/yy]
				[party 2]	[sc id 2]	[ncr]	["]	["]	["]		[n/a]	[no]	["]	["]
				[party n]	[sc id n]	[er]	["]	["]	["]		[20]	[yes]	["]	["]
[name/number 2]		[zone name]	[zone name]	[party 1]	[sc id 1]	[er]	[MW]	[MW]	[MW]	[1400]	[20]	[yes]	["]	["]
				[party 2]	[sc id 2]	[ncr]	["]	["]	["]		[n/a]	[no]	["]	["]
				[party n]	[sc id n]	[er]	["]	["]	["]		[20]	[yes]	["]	["]
[name/number n]		[zone name]	[zone name]	[party 1]	[sc id 1]	[er]	[MW]	[MW]	[MW]	[1500]	[20]	[yes]	["]	["]
				[party 2]	[sc id 2]	[ncr]	["]	["]	["]		[n/a]	[no]	["]	["]
				[party n]	[sc id n]	[er]	["]	["]	["]		[20]	[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.

SCHEDULING COORDINATOR APPLICATION PROTOCOL

SCHEDULING COORDINATOR APPLICATION PROTOCOL

Table of Contents

SCHEDULING COORDINATOR APPLICATION PROTOCOL (SCAP)

SCAP 1 OBJECTIVE, DEFINITION AND SCOPE

SCAP 1.1 Objective

The objective of the SCAP is to inform an SC Applicant of the actions it must take and information it must provide to become an approved Scheduling Coordinator (SC). The SCAP also describes the actions the ISO will take to evaluate a submitted application.

SCAP 1.2 Definitions

SCAP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix refers to a Section or an Appendix of the ISO Tariff unless otherwise indicated. References to SCAP are to this Protocol or to the stated paragraph of this Protocol.

SCAP 1.2.2 Special Terms for this Protocol

In this Protocol, the following words and expressions shall have the meaning set forth below:

"Electronic Data Interchange" (EDI) means 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.

"ISO Application File Template" means 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.

"SC Customer" means a customer of the SC Applicant or a Scheduling Coordinator for whom the SC provides services relevant to the ISO Controlled Grid.

"Validation, Estimation and Editing" (VEE) applies to Meter Data directly acquired by the ISO. Validation is the process of checking the data to ensure that it is contiguous, within pre-defined limits and has not been flagged by the meter. Estimation and Editing is the process of replacing or making complete Meter Data by using data from redundant meters, schedules, PMS or, if necessary, statistical estimation.

"Value Added Network" (VAN) means 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.

SCAP 1.2.3 Rules of Interpretation

(a) If the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference 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 Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

SCAP 1.3 Scope

SCAP 1.3.1 Scope of Application to Parties

The SCAP will apply to:

(a) Scheduling Coordinator Applicants;

(b) Scheduling Coordinators; and

(c) the ISO.

SCAP 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.

SCAP 2 PROCEDURE TO BECOME A SCHEDULING COORDINATOR

SCAP 2.1 SC Applicant makes a Request

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

SCAP 2.2 ISO Information

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

(a) the SC Application Form (including the ISO Application File Template which is Appendix C);

(b) the ISO Tariff and ISO Protocols;

(c) pro forma Meter Service Agreements and Interim Black Start Agreement;

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

(e) a pro forma letter of understanding for payment for SC Applicants with Approved Credit Ratings, guarantee, letter of credit and escrow agreement for the ISO Security Amount, all of which will be in a form acceptable to the ISO.

SCAP 2.3 Duplicate Information

If two or more SCs apply simultaneously to register with the ISO for a single meter or Meter Point for an ISO Metered Entity or if an SC applies to register with the ISO for a meter or Meter Point for an ISO Metered Entity for which an SC has already registered, the ISO will return the application with an explanation that only one SC may register with the ISO for the meter or Meter Point in question and that an SC has already registered or that more than one SC is attempting to register for that meter or Meter Point. The ISO will send the SC Applicant the name and address of the applicable SC or SC Applicant.

SCAP 2.4 SC Applicant returns Application

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

SCAP 2.5 Notice of Receipt

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

SCAP 2.6 ISO Review of Application

Within 14 days after receiving an application, the ISO will notify the SC Applicant whether the SC Applicant has submitted all necessary information as set forth in ISO Tariff Sections 2.2.3 and 2.2.4, and the ISO Application File Template requirements.

SCAP 2.6.1 Information Requirements

The SC Applicant must submit with its application:

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

(b) financial and security information as set forth in ISO Tariff Section 2.2.3.2; and

(c) the prescribed non-refundable application fee.

SCAP 2.6.2 SC Applicant's Obligation for Contracts

An SC Applicant must certify that it is duly authorized to represent the Generators and Loads, which are its SC Customers and must further certify that:

(a) represented Generators have entered into Participating Generator Agreements with the ISO;

(b) represented UDCs have entered into UDC agreements with the ISO;

(c) represented ISO Metered Entities have entered into Meter Service Agreements with the ISO;

(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.

SCAP 2.7 Deficient Application

In the event the application is deficient, the ISO will send a written notification of the deficiency to the SC Applicant within 14 days of receipt by the ISO of the application explaining the deficiency and requesting additional information.

SCAP 2.7.1 SC Applicant's Additional Information

Once the ISO requests additional information pursuant to Section 2.7, the SC Applicant has 7 days, or such longer period as the ISO may agree, to provide the additional material requested by the ISO.

SCAP 2.7.2 No Response from SC Applicant

If the SC Applicant does not submit additional information within 7 days or the longer period referred to in SCAP 2.7.1, the application may be rejected by the ISO in accordance with ISO Tariff Section 2.2.4.2(d).

SCAP 3 ISO APPROVAL OR REJECTION OF AN APPLICATION

SCAP 3.1 Approval or Rejection Letter

(a) If the ISO approves the application, it will send an approval letter with a signed SC Agreement for the SC Applicant's signature and any required software licensing agreement.

(b) If the ISO rejects the application, the ISO will send a rejection letter stating one or more of the following grounds:

i. incomplete information;

ii. non-compliance with security requirements;

iii. non-compliance with third party contractual obligations;

iv. non-compliance with technical requirements; or

v. non-compliance with any other SCAP or ISO Tariff requirements.

Upon request, the ISO will provide guidance as to how the SC Applicant can cure the grounds for the rejection.

SCAP 3.2 Time for Processing Application

The ISO will make a decision whether to accept or reject the application within 14 days of receipt of the application. If more information is requested, the ISO will make a final decision within 14 days of the receipt of all outstanding or additional information requested.

SCAP 4 SC APPLICANT'S RESPONSE

SCAP 4.1 SC Applicant's Acceptance

If the ISO accepts the application, the SC Applicant must return an executed SC Agreement, Meter Service Agreements, Interim Black Start Agreements and letter of credit, guarantee or escrow agreement for the ISO Security Amount, as applicable.

SCAP 4.2 SC Applicant's Rejection

SCAP 4.2.1 Resubmittal

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

SCAP 4.2.2 Appeal

The SC Applicant may also appeal against the rejection of an application by the ISO. An appeal must be submitted within 28 days following the rejection of its application, as set forth in ISO Tariff Section 2.2.4.3 and 2.2.4.4.

SCAP 5 POST APPLICATION PROCEDURES PRIOR TO FINAL CERTIFICATION

SCAP 5.1 SC's Administrative, Financial and Technical Requirements

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

(a) provided the technical/operational information required to complete the ISO Application File Template, and to comply with ISO Tariff Section 10.6;

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

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

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

(e) provided its bank account information and arranged for Fed-Wire System transfers as defined in SABP 1.2.2;

(f) submitted a timetable for completion of its operational facilities, in order to coordinate site visits by ISO staff to ensure compliance with the ISO Tariff Section 2.2.7.1; and

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

SCAP 6 FINAL CERTIFICATION OF SC APPLICANT

The SC Applicant will become a Scheduling Coordinator when:

(a) its application has been accepted;

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

(c) the SC Applicant has met the financial requirements of ISO Tariff Section 2.2.3.2; and

(d) the SC Applicant has fulfilled all technical/operational requirements of ISO Tariff Section 2.2.7.1, SCAP 5.1 and the ISO Application File Template.

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

SCAP 7 SC'S ONGOING OBLIGATIONS AFTER CERTIFICATION

SCAP 7.1 Scheduling Coordinator's Obligation to Report Changes

SCAP 7.1.1 Obligation to Report a Change in Filed Information

Each SC has an ongoing obligation to inform the ISO of any changes to any of the information submitted by it to the ISO as part of the application process, including any changes to the additional information requested by the ISO. SCAP Appendix B sets forth the procedures for changing the SC's information and timing of notifying the ISO of such changes.

SCAP 7.1.2 Obligation to Report a Change in Credit Rating

The SC has an ongoing obligation to inform the ISO within 3 Business Days if its Approved Credit Rating has been reduced below the ISO requirements.

SCAP 7.1.3 Obligation to Maintain ISO Security Amount

The SC has an ongoing obligation to maintain the ISO Security Amount as set forth in ISO Tariff Section 2.2.7.3. Alternatively, the SC has the right to inform the ISO of an improvement in its credit status and have the ISO review a new Approved Credit Rating, in order to determine if the ISO Security Amount is still necessary.

SCAP 7.2 ISO's Response for Failure to Inform

SCAP 7.2.1 Failure to Promptly Report a Material Change

If a SC fails to inform the ISO of a material change in its information provided to the ISO, which may affect the reliability or safety of the ISO Controlled Grid, or the financial security of the ISO, the ISO may suspend or terminate the SC's rights under the ISO Tariff in accordance with the terms of ISO Tariff Sections 2.2.7.3 and 2.2.4 respectively. If the ISO intends to terminate the SC's rights it shall file a Notice of Termination with FERC. Such termination shall be effective upon acceptance by FERC of a Notice of Termination.

SCAP 7.2.2 Failure to Report a Lost Approved Credit Rating

If the SC's Approved Credit Rating is reduced below the ISO requirements, the ISO will suspend the SC's scheduling rights under the ISO Tariff, until the SC submits another form of security in accordance with ISO Tariff Sections 2.2.3.2 and 2.2.7.3.

SCAP 7.2.3 Failure to Maintain ISO Security Amount

If the SC's estimated aggregate liability is greater than its ISO Security Amount, the ISO will reject any schedule in accordance with ISO Tariff Section 2.2.7.3 until such time as the SC increases its ISO Security Amount or decreases its outstanding payment balance.

SCAP 7.3 SC's Obligation to Uphold all SC Commitments

Each SC has an ongoing obligation to uphold and be bound by all the terms and conditions of the ISO Tariff as long as it remains a SC.

SCAP 8 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

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

SCAP APPENDIX A

SCHEDULING COORDINATOR APPLICATION FORM

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

I. **<u>Administrative Requirements</u>**

SC Applicant's Legal Name:

____

Address of principal place of business:

____

____

____

Authorized Representative:

____

Address:

____

____

Phone: ______________________________________

Fax: ______________________________________

E-mail: ______________________________________

Type of entity:

____
_

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

State of Incorporation or Partnership: ______________________

Proposed commencement date for service: ____________________

II. SC Customer Information

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

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

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

III. Security Requirement

3.1 The SC Applicant has an Approved Credit Rating as set forth in the ISO Tariff: (yes/no).

The SC Applicant's credit rating is ___________.

Please attach certified documentation of an Approved Credit Rating from Standard & Poor's, Moody's Investors Services or the equivalent. SC Applicant must also submit, before final certification, an executed letter of understanding for payment providing contact details in case of default. **OR**

3.2 The SC Applicant will provide an irrevocable and unconditional guarantee from a company which has an Approved Credit Rating: (yes / no).

The SC Applicant must submit a signed irrevocable and unconditional guarantee in an ISO approved form and certified documentation of the other company's Approved Credit Rating before final certification. **OR**

3.3 The SC Applicant will provide an irrevocable and unconditional letter of credit: (yes / no).

Amount: $_______________.

The SC Applicant must submit a signed irrevocable and unconditional letter of credit in an ISO approved form before final certification. **OR**

3.4 The SC Applicant will provide a cash deposit: (yes / no).

Amount: $____________. The SC Applicant must enter into an escrow agreement in an ISO approved form before final certification. **AND**

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

IV. <u>Technical Requirements</u>

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

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

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

V. <u>Third Party Contractual Requirements</u>

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

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

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

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

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

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

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

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

VI. Additional Information and Obligations

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

6.2 Subject to the ISO Tariff, the SC Applicant agrees to promptly report to the ISO within seven (7) Business Days or earlier any changes regarding the information provided by it referred to in the SCAP and in the application with the exception of the security requirement data referred to in Part III of SCAP Appendix A which must be updated within three (3) Business Days. The Scheduling Coordinator shall be responsible if a failure to submit revised technical data more promptly extends the period during which schedules are rejected by the ISO.

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

Please make check payable to:

The California Independent System Operator Corporation

6.4 SC Applicant agrees to promptly execute and return the SC Agreement, Meter Service Agreements, Interim Black Start Agreements, software licensing agreement, letter of understanding, letter of credit, guarantee, escrow agreement, as applicable, and Fed-Wire System bank account number, after receiving its application approval letter from the ISO.

6.5 Final certification is contingent upon SC Applicant fulfilling all financial and technical requirements as referenced in the SCAP (including Appendix C, the ISO Application File Template).

SC Applicant certifies by its signature on this Application Form that:

(1) all information it is submitting is correct and accurate; and that

(2) the SC Applicant has read and agrees to be bound by the ISO Tariff as may be in force or amended from time to time.

Name of Organization:

____

SC Applicant's Name (please print):

____

SC Applicant's Title:

____

SC Applicant's Signature:

____

State of ___________________________}

ss

County of _________________________}

[**SEAL]**

Sworn and subscribed

before me this _____ day of

___________________,19___.

Notary's Signature: ____

Please send application and required information to:

California Independent System Operator Corporation

c/o Schedule Coordinator Application Processing Office

151 Blue Ravine Road,

Folsom, CA 95630

SCAP APPENDIX B

Procedures for Changes or Additions to Scheduling Coordinator's (SC's) Information

The SC must update, amend and / or correct the information originally submitted to the ISO during the SC application process using the format set forth in this Appendix and / or a revised Appendix C, the ISO Application File Template. The SC must submit all changes or additional information by first class postage paid mail to:

California Independent System Operator Corporation
c/o SC Application Processing Office
151 Blue Ravine Road
Folsom, CA 95630

The SC must notify the ISO of any change to the information that it has previously submitted to the ISO, or any additional information, at least three Business Days before the change will take effect.

The ISO will send a written acknowledgment of receipt of the SC's changes within three Business Days of receipt. The receipt shall be sent to the address on file with the ISO or the address specified in the notice of change received by the ISO.

Prior Information

____
____
____

New Information

____
____
____

Explanation and Reason for Change

____
____
____

SCAP APPENDIX C

ISO APPLICATION FILE TEMPLATE

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

SCHEDULING PROTOCOL

SCHEDULING PROTOCOL

Table of Contents

SCHEDULING PROTOCOL (SP)

SP 1 OBJECTIVES, DEFINITIONS AND SCOPE

SP 1.1 Objectives

The objectives of this Protocol are:

(a) to process the scheduling input data (submitted to the ISO under the Ancillary Service Requirements Protocol (ASRP), the Demand Forecasting Protocol (DFP), and the Schedules and Bids Protocol (SBP)) in order to develop Final Schedules for the Day-Ahead and Hour-Ahead Markets (real-time management of the ISO Controlled Grid is addressed in the Dispatch Protocol (DP));

(b) to provide for the scheduling of the use of Firm Transmission Rights and use of transmission service rights under Existing Contracts;

(c) to assist the ISO in purchasing Ancillary Services; and

(d) to manage Congestion.

SP 1.2 Definitions

SP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is to a Section or an Appendix of the ISO Tariff. References to SP are to this Protocol or to the stated paragraph of this Protocol.

SP 1.2.2 [Not used]

SP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol 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 Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

(e) References to time are references to the prevailing Pacific time.

SP 1.3 Scope

SP 1.3.1 Scope of Application to Parties

The SP applies to the following entities:

(a) Scheduling Coordinators (SCs);

(b) Utility Distribution Companies (UDCs);

(c) Participating Transmission Owners (PTOs);

(c) interfacing Control Area operators in accordance with Inter-Control Area agreements entered into with the ISO, to the extent the agreement between the Connected Entity and the ISO so provides; and

(d) the Independent System Operator (ISO).

SP 1.3.2 Liability of 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.

SP 2 INTERFACE REQUIREMENTS

The WEnet interface requirements and associated information requirements are described in the SBP.

SP 3 Time Lines

(a) Consistent with Sections 2.2.12.1 and 2.5.2.2 of the ISO Tariff, the ISO may implement any temporary variation or waiver of timing requirements contained in this SP (including the omission of any step) if any of the following criteria are met:

(i) 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;

(ii) the ISO requires additional time to fulfill its responsibilities pursuant to Section 2.2.2 of the ISO Tariff;

(iii) problems with data or the processing of data cause a delay in receiving or issuing Schedules or publishing information on the WEnet;

(iv) problems with telecommunications or computing infrastructure cause a delay in receiving or issuing Schedules or publishing information on the WEnet; or

(v) 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.

(b) If the ISO temporarily implements a waiver or variation of such timing requirements (including the omission of any step) consistent with Section 2.2.12.1 of the ISO Tariff and SP 3(a), 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; and

(iv) reasons for the temporary waiver or variation.

(c) 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.

(d) 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.

(e) The incorporation of the scheduling of the use of rights under Existing Contracts into the ISO's Day-Ahead, Hour-Ahead and real-time processes is additionally described in SP 7 and in the SBP.

SP 3.1 Balanced Schedules

SP 3.1.1 Types of Balanced Schedules

A Schedule shall be treated as a Balanced Schedule when the SC's aggregate Generation and external imports (adjusted for Transmission Losses) and Inter-Scheduling Coordinator Energy Trades (whether purchases or sales), equal the SC's aggregate Demand Forecast, including external exports, with respect to all entities for which the SC schedules. On an interim basis, the ISO may assist SCs in matching Inter-Scheduling Coordinator Energy Trades.

SP 3.1.2 Preferred Schedules

The Preferred Schedule is the initial Schedule submitted by a SC in the Day-Ahead Market or Hour-Ahead Market. A Preferred Schedule shall be a Balanced Schedule submitted to the ISO by each SC on a daily and/or hourly basis.

SP 3.1.3 Seven-Day Advance Schedules

SCs may submit Balanced Schedules for up to seven (7) Trading Days at a time, representing the SC'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 SC, a Schedule submitted in advance of this deadline for submission will become the SC'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. As part of the scheduling and validation process, the ISO will calculate and publish, via WEnet, the GMMs applicable to the Day-Ahead and Hour-Ahead Markets eight (8) days ahead of the Trading Day to which they relate, as described in SP 4.

SP 3.1.4 Suggested Adjusted Schedules

If the sum of SCs' Preferred Schedules would cause Congestion across any Inter-Zonal Interface, the ISO shall issue Suggested Adjusted Schedules to all SCs in the Day-Ahead Market only. 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. The ISO will publish as public information, via the WEnet, estimated Usage Charges for Energy transfers between Zones.

SP 3.1.5 Revised Schedules

Following receipt of a Suggested Adjusted Schedule, a SC 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.

SP 3.1.6 Final Schedules

If the ISO notifies a SC that there will be no Congestion on the ISO Controlled Grid based on the Preferred Schedules submitted by all

SCs, the Preferred Schedule shall become that SC's Final Schedule. If the ISO has adjusted the SC's Preferred Schedule to match Inter-Scheduling Coordinator Energy Trades then the adjusted Preferred Schedule shall become that SC's Final Schedule. If the ISO notifies a SC that there will be no Congestion on the ISO Controlled Grid based on the Revised Schedules submitted by all SCs, the Revised Schedule shall become that SC's Final Schedule. If the ISO has adjusted the SC's Revised Schedule to match Inter-Scheduling Coordinator Energy Trades then the adjusted Revised Schedule shall become that SC'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 SCs 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 SCs.

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 SP 4, 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 2.5.2.2.

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 SCs 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 SC 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, SCs 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 By 6:00 am, One Day Ahead

By 6:00 am on the day ahead of the Trading Day (for example, by 6:00 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 3.2.3 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 SCs' 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 SCs' 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 SCs 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, SCs may submit contract usage templates (in accordance with the SBP) 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

SP 3.2.6.1 Actions by SCs 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) SCs will submit their Preferred Day-Ahead Schedules to the ISO in accordance with the SBP;

(b) SCs will submit, as part of their Preferred Day-Ahead Schedules, their Adjustment Bids, if any, to the ISO in accordance with the SBP;

(c) SCs will submit their Ancillary Services bids, if any, to the ISO in accordance with the SBP and SP 9;

(d) SCs will submit their schedules for self-provided Ancillary Services, if any, to the ISO in accordance with the SBP and SP 9;

(e) the ISO will validate (in accordance with the SBP) all SC submitted Preferred Day-Ahead Schedules for Energy and Adjustment Bids and may assist SCs 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 (in accordance with the SBP) all SC 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 (in accordance with the SBP) all contract usage templates received from SCs for scheduled uses of Existing Contract rights and Firm Transmission Rights;

(h) the ISO will validate that all SC submitted Preferred Day-Ahead Schedules are compatible with the RMR requirements of which SCs were notified for that Trading Day and with the SCs' elected options for delivering the required Energy;

(i) the ISO will start the first iteration of Inter-Zonal Congestion Management process as described in SP 10; and

(j) the ISO will start the Ancillary Services bid evaluation process as described in SP 9;

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 the SBP. The purpose of this is to allow the SCs, 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 SC's pre-validation to that SC 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. SCs 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 SC'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 SCs 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 SCs can check whether or not their submittal will pass the ISO's validation checks between 9:00 am and 10:00 am), SCs 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 SCs 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 SC's 10:00 am validation to that SC 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 SCs 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 SCs 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 SCs' 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 SCs 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 SCs 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 SC's portfolio will be based on the Adjustment Bids provided by the SC.

(e) The ISO will notify each SC 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 SCs which submitted Preferred Day-Ahead Schedules at 10:00 am, including the SCs 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 SCs 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 SC'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 SCs and the ISO

(a) SCs will submit Revised Day-Ahead Schedules to the ISO, in response to the ISO's Suggested Adjusted Day-Ahead Schedules, in accordance with the SBP;

(b) SCs 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 in accordance with the SBP;

(c) SCs will submit revised Ancillary Services bids, if any, to the ISO in accordance with the SBP and SP 9;

(d) SCs will submit their schedules for self-provided Ancillary Services, if any, to the ISO in accordance with the SBP and SP 9;

(e) the ISO will validate (in accordance with the SBP) all SC submitted Revised Day-Ahead Schedules for Energy and Adjustment Bids and may assist SCs 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 (in accordance with the SBP) all SC 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 (in accordance with the SBP) all contract usage templates received from SCs 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 SP 10;

(i) the ISO will start the second (and final) iteration of the Ancillary Services bid evaluation process as described in SP 9; and

(j) the ISO will use the SC's Preferred Day-Ahead Schedule in the event the SC does not submit a Revised Day-Ahead Schedule. If a SC 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 SC'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 the SBP. The purpose of this is to allow the SCs, 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 SC's submittal to that SC 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. SCs 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 SC'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 SCs 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, SCs 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 SCs 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 SC's 12:00 noon validation to that SC 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 SCs 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 SCs 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 SCs' 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 SCs 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 SCs 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 SC's portfolio will be based on the Adjustment Bids provided by the SC.

(e) The ISO will notify each SC 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 SP 10;

(b) the ISO will provide, via WEnet, Final Day-Ahead Schedules to all SCs 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 SCs 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 SCs 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 SCs 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 SC intertie schedules will be examined. If the other Control Area's records are determined to be correct, the ISO will notify the affected SC. If the other Control Area Operator's records are in error, no changes will be required by the ISO or affected SCs. The affected SC 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 SCs, 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 SCs 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 SCs 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 SC 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 SC 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 SCs' 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 an SC's Final Day-Ahead Schedule or Ancillary Service commitments, the ISO will notify the SC, via the WEnet, of its available contract capacity. Additionally, the ISO will validate SCs' scheduled usage against SCs' contract usage templates and notify SCs 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 SCs and the ISO

(a) SCs will submit their Preferred Hour-Ahead Schedules to the ISO in accordance with the SBP;

(b) SCs will submit, as part of their Preferred Hour-Ahead Schedules, their Adjustment Bids, if any, to the ISO in accordance with the SBP;

(c) SCs will submit their Ancillary Services bids, if any, to the ISO in accordance with the SBP and SP 9;

(d) SCs will submit their Schedules for self-provided Ancillary Services and Inter-Scheduling Coordinator Ancillary Service Trades, if any, to the ISO in accordance with the SBP and SP 9;

(e) the ISO will validate (in accordance with the SBP) all SC submitted Preferred Hour-Ahead Schedules for Energy and Adjustment Bids;

(f) SCs 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 (in accordance with the SBP) all contract usage templates received from SCs for scheduled uses of Existing Contract rights and Firm Transmission Rights;

(h) the ISO will validate (in accordance with the SBP) all SC 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 SP 10;

(j) the ISO will start the Ancillary Services bid evaluation process as described in SP 9; and

(k) the ISO will validate that all SC submitted Preferred Hour-Ahead Schedules are compatible with the RMR requirements of which SCs were notified for that Trading Day and with the SCs' 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 the SBP. The purpose of this is to allow the SCs, 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 SC's submittal to that SC 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. SCs 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 SC'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. SCs 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 SCs 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 SC's two hour and fifteen minute ahead validation to that SC 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 SC's Final Day-Ahead Schedule, without any Day-Ahead Adjustment Bids or Day-Ahead Ancillary Service bids, in the event the SC's Preferred Hour-Ahead Schedule fails validation. If a SC desires to submit an Hour-Ahead Schedule that is different than its Final Day-Ahead Schedule the SC 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 SC'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 SP 10;

(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 SCs 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 SCs 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 for use under the DP and to the SCs 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 SC 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 SC 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 SCs. If the other Control Area operator's records are determined to be correct, the ISO will notify the affected SC. The ISO will manually adjust the affected SC's schedule to conform with the other Control Area operator's net schedule, in real time, and the affected SC will be responsible for managing any resulting Energy imbalance.

SP 4 TRANSMISSION SYSTEM LOSS MANAGEMENT

SP 4.1 Overview

(a) A SC must ensure that each Schedule it submits to the ISO is a Balanced Schedule in which aggregate Generation and external imports (adjusted for Transmission Losses) and Inter-Scheduling Coordinator Energy Trades equals the aggregate Forecast Demand and external exports. The ISO will, for this purpose, 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. Inter-Scheduling Coordinator Energy Trades will not be subject to such adjustments, beyond the impact of GMMs on the respective SC's Generation and external imports. The ISO will, in accordance with this SP 4, derive a location specific GMM for each Generating Unit and external import on the ISO Controlled Grid.

(b) At all times, the ISO will make available GMMs for the seven Trading Days starting with the Trading Day after the next Trading Day. Each day, at 6:00 pm, the ISO will calculate and publish, via WEnet, the GMMs applicable to the Day-Ahead Markets and the Hour-Ahead Markets for the eighth (8^{th}) Trading Day forward. 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.

SP 4.2 Generator Meter Multipliers (GMMs)

SP 4.2.1 Derivation of GMMs

(a) The ISO will utilize the Power Flow Model to determine the GMMs which will be used to allocate, to each Generating Unit and external import, scheduled and Ex Post Transmission Losses.

(b) For each Settlement Period, the GMMs will be first calculated before SCs submit Day-Ahead Preferred Schedules. Prior to the time when SCs are required to submit their Day-Ahead Preferred Schedules, the ISO will forecast the total Control Area Demand. This forecast, along with the ISO forecast of Generation and Demand patterns throughout the ISO Control Area, will be used to develop estimated GMMs for each Generating Unit and each external import. The ISO will calculate and publish (in accordance with SP 3.2.1) 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.

(c) The ISO will utilize the real-time Power Flow Model to calculate Ex Post GMMs to allocate Ex Post Transmission Losses to each Generating Unit and each external import. This run of the Power Flow Model will use metered Generation and Demand. 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.

SP 4.2.2 Methodology for Calculating Transmission Losses

(a) The ISO Power Flow Model will be utilized to calculate the effects on total Transmission Losses at each Generating Unit and Scheduling Point by calculating the sensitivity of injecting Energy at each Generating Unit bus or Scheduling Point to serve an increment of Demand distributed proportionately throughout the ISO Control Area. This will produce the Full Marginal Loss Rate at each Generating Unit and Scheduling Point.

(b) The ISO will then determine the ratio of expected Transmission Losses to the total Transmission Losses that would be collected if Full Marginal Loss Rates were utilized to determine Transmission Losses. This ratio is referred to as the Loss Scale Factor.

(c) The ISO will then multiply the Loss Scale Factor by the Full Marginal Loss Rate at each Generating Unit or Scheduling Point to determine each Generating Unit's or external import's Scaled Marginal Loss Rate. The GMM is calculated by subtracting the Scaled Marginal Loss Rate from unity.

SP 4.3 Existing Contracts and Transmission Losses

Certain Existing Contracts may have requirements for Transmission Loss accountability which differ from the provisions of this SP 4. Each PTO will be responsible for recovering any deficits or crediting any surpluses, associated with differences in assignment of Transmission Loss requirements, through its bilateral arrangements or its Transmission Owner's Tariff. The ISO will not undertake the settlement or billing of any such differences under any Existing Contract.

SP 5 RELIABILITY MUST-RUN GENERATION

SP 5.1 Procurement of Reliability Must-Run Generation by the ISO

SP 5.1.1 Annual Reliability Must-Run Forecast - Technical Evaluation

On an annual 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.

SP 5.1.2 Annual Reliability Must-Run Forecast - Technical Studies

The ISO will perform off-line technical studies, adopt existing procedures developed by PTOs and/or develop new operating procedures to identify the Reliability Must-Run requirements for various levels of system Demand.

SP 5.2 Designation of Generating Unit as Reliability Must-Run

The ISO will have the right at any time based upon ISO Controlled Grid technical analyses and studies to designate or disqualify a Generating Unit as a Reliability Must-Run Unit.

SP 5.3 Scheduling of Reliability Must-Run Generation

The ISO will notify SCs of any Reliability Must-Run Units which the ISO requires to run during a Trading Day no later than 5:00 am on the day before that Trading Day, as described in SP 3.2.1.1.

SP 5.4 [UNUSED]

SP 6 [UNUSED]

SP 7 MANAGEMENT OF EXISTING CONTRACTS FOR TRANSMISSION SERVICE

SP 7.1 Obligations of Participating Transmission Owners and Scheduling Coordinators

SP 7.1.1 Participating Transmission Owners

Prior to the ISO accepting Schedules which include the use of Existing Rights, the Responsible PTO (as defined in the SBP) must have provided the ISO with the information required in the Transmission Control Agreement and the SBP, including transmission rights/curtailment instructions ("instructions") supplied in a form and by means of communication specified by the ISO.

SP 7.1.2 Scheduling Coordinators

The ISO will accept valid Schedules from a Responsible PTO that is the SC for the Existing Contract rights holders, or from Existing Contract rights holders that are SCs, or that are represented by a SC other than the Responsible PTO. Schedules submitted by SCs to the ISO which include the use of Existing Rights must be submitted in accordance with the SBP and this SP.

SP 7.2 Allocation of Forecasted Total Transfer Capabilities

SP 7.2.1 Categories of Transmission Capacity

As used in this SP, 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 SP 7.4. 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 SP 3.2.1. In accordance with Section 2.4.4.5.1.4 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.

SP 7.2.2 Prioritization of Transmission Uses

The following rules are designed to enable the ISO to honor Existing Contracts in accordance with Sections 2.4.3 and 2.4.4 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 SP 7.2.1, 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 accordance with the SBP. 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 SP 7.2.3 for a summary of allowable linkages). Scheduling and curtailment priorities associated with each category will be defined by SCs through the use of contract usage templates submitted as part of their Schedules as described in the SBP.

(a) Transmission capacity for Schedules will be made available to holders of firm Existing Rights in accordance with this SP 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/MWh to -$140,000/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 SCs 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 SCs 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 SP 10, 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 SCs 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 SCs 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 SCs as $0.00/MWh Adjustment Bids. Therefore, there will be no contract reference number associated with non-firm Existing Contract rights.

SP 7.2.3 Allowable Linkages

As indicated in SP 7.2.2, 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.

SP 7.3 The Day-Ahead Process

SP 7.3.1 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 SCs on behalf of the rights holders for conformity with the instructions previously provided by the Responsible PTO in accordance with the SBP. Invalid Schedules will be rejected and the ISO will immediately communicate the results of each SC's validation to that SC via WEnet.

SP 7.3.2 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).

SP 7.3.3 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 and subject to its Protocols 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).

SP 7.3.4 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 SP 7.2.2 (c)) 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 SP 7.2.2 (a)) to the extent necessary.

SP 7.4 The Hour-Ahead Process

SP 7.4.1 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, in accordance with the SBP. Invalid schedules will be rejected and the ISO will immediately communicate the results of each SC's validation to that SC via WEnet.

SP 7.4.2 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).

SP 7.4.3 Acceptance of Firm Transmission Schedules

Before allocating any remaining transmission capacity under the following provisions of this SP 7, the ISO will accept Schedules associated with firm Existing Rights (subject to validation under SP 7.4.1), allocating transmission capacity for use by these rights holders.

SP 7.4.4 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 SP 7.3.3. 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 SP 7.5.

SP 7.4.5 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 SP 7.2.2 (c)) 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 SP 7.2.2 (a)) to the extent necessary.

SP 7.5 The ISO's Real-Time Process

Consistent with SP 7.4.4, the ISO will honor those scheduling flexibilities that may be exercised by holders of Existing Rights through their respective SCs 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 SP 7.5.1 and SP 7.5.2 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).

SP 7.5.1 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 SC 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 SC 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 in accordance with the SBP. The ISO will manually adjust the SC's schedule to conform with the other Control Area's net schedule in real time, and the notifying SC will be responsible for and manage any resulting Energy imbalance. These Imbalance Energy deviations will be priced and accounted to the SC representing the holder of Existing Rights in accordance with the SABP.

SP 7.5.2 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 SC representing the holder of Existing Rights in accordance with the SABP.

SP 8 OVERGENERATION MANAGEMENT

SP 8.1 Real-Time Overgeneration Management

Overgeneration management in real time will be conducted in accordance with the DP.

SP 9 DAY/HOUR-AHEAD ANCILLARY SERVICES MANAGEMENT

SP 9.1 Bid Evaluation and Scheduling Principles

The ISO will evaluate Ancillary Services bids based on the following principles:

(a) the ISO will not differentiate between bidders other than through reserve (Regulation and Operating Reserves) price and capability to provide the reserve service, and the required locational mix of services;

(b) to minimize the costs to users of the ISO Controlled Grid, the ISO will select the bidders with lowest bids for reserve which meet its technical requirements, including location and operating capability;

(c) the ISO will (to the extent available) procure sufficient Ancillary Services to meet its technical requirements as defined in the ASRP;

(d) the ISO will evaluate and price only those Ancillary Services bids received in accordance with the SBP;

(e) the ISO will require SCs to honor their Day-Ahead Ancillary Services schedules and/or bids when submitting their Hour-Ahead Ancillary Services schedules and/or bids. 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 such capacity to the extent scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or to the extent 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 at the Market Clearing Price in the Hour-Ahead Market for the same Settlement Period for the Ancillary Service capacity concerned. Increases in each Scheduling Coordinator's self-provided Ancillary Services 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 Load. 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;

(f) 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; and

(g) 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.

SP 9.2 Sequential Evaluation of Bids

(a) When SCs bid into the Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve markets, the same resource capacity may be offered into more than one of these Ancillary Services markets at the same time. The ISO will evaluate bids in the reserve markets for Regulation, Spinning Reserve, Non-Spinning Reserve and Replacement Reserve sequentially and separately in the following order:

(i) Regulation

(ii) Spinning Reserve

(iii) Non-Spinning Reserve; and

(iv) Replacement Reserve.

(b) SCs are allowed to specify different reserve prices and different Energy prices for each Ancillary Service they bid. SCs can bid the same resource capacity into any one or all of the Ancillary Service markets they desire. Any resource capacity accepted by the ISO in one of these reserve markets will be deducted from the resource capacity bid into the other reserve markets, except that resource capacity accepted in the Regulation market that represents the downward range of movement accepted by the ISO will not be deducted from the resource capacity bid into other reserve markets.

SP 9.3 Scheduling Ancillary Services Resources

(a) SCs are allowed to self-provide all or a portion of the following Ancillary Services to satisfy their obligations to the ISO:

(i) Regulation;

(ii) Spinning Reserve;

(iii) Non-Spinning Reserve; and

(iv) Replacement Reserve.

(b) The ISO will reduce the quantity of Ancillary Services it competitively procures by the corresponding amount of the Ancillary Services that SCs self-provide.

(c) The ISO shall prepare supplier schedules for Ancillary Services (both self-provided and purchased by the ISO) for the Day-Ahead Market and the Hour-Ahead Market.

(d) The Ancillary Services schedules shall contain the information set out in the SBP for each Settlement Period of the following Trading Day in the case of the Day-Ahead Schedules or for a specific Settlement Period in the case of Hour-Ahead Schedules.

(e) Once the ISO has given SCs notice of the Day-Ahead and Hour-Ahead Schedules, these schedules represent binding commitments made in the reserve markets between the ISO and the SCs concerned. 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 such capacity to the extent scheduled self-provision is decreased between the Day-Ahead and Hour-Ahead Markets, or to the extent 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 replacement shall be at 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 Unit or other resources on behalf of which the Scheduling Coordinator buys back the capacity, 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.

(f) Any minimum Energy output associated with Regulation and Spinning Reserve services shall be the responsibility of the SC, as the ISO's auction does not compensate the SC for the minimum Energy output of its Generating Units or System Unit, if any, bidding to provide these services. Accordingly, the SCs shall adjust their Balanced Schedules to accommodate the minimum Energy outputs required by the Generating Units or System Units, if any, included in the Ancillary Services schedules.

(g) SCs providing one or more of the Ancillary Services cannot change the identification of the Generating Units System Units or external imports of System Resources, if any, or Curtailable Demands offered in the Day-Ahead Market, in the Hour-Ahead Market, or in the Real Time Market (except with respect to System Units, if any, in which case SCs 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)).

SP 9.4 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).
$Cap_{ijt}max$	=	the maximum amount of reserve that can be scheduled by the ISO with respect to a SC'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 ($Cap_{ijt} \leq Cap_{ijt}max$)
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.

SP 9.5 Regulation Bid Evaluation and Pricing

SP 9.5.1 Regulation Bid Evaluation

(a) Based on the quantity and location of the system requirements, the ISO will select Generating Units, System Units, and System Resources with the Regulation bids which minimize the sum of the total Regulation bids of the Generating Units, System Units, and System Resources selected subject to two constraints:

(i) the sum of the selected amounts of Regulation bid must be greater than or equal to the required amount of Regulation; and

(ii) the amount of Regulation bid for each Generating Unit, System Unit, or System Resource must be less than or equal to that Generating Unit's, System Unit's, or System Resource's ramp rate times $Period_{minutes}$ where $Period_{minute}$ 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.

(b) The total Regulation bid for each Generating Unit, System Unit, or System Resource is calculated by multiplying the reserve reservation bid price by the amount of Regulation bid. Subject to any locational requirements, the ISO will accept winning Regulation bids in accordance with the following criteria:

$$Min \sum_{i,j} TotalBid_{ijt}$$

subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

and

$$Cap_{ijt} \leq Cap_{ijt} \max$$

where:

$TotalBid_{ijt}$ = $Cap_{ijt} * CapRes_{ijt}$

Requirement = *Amount of upward and downward movement (Regulation) required by the ISO*.

SP 9.5.2 Regulation Price Determination

The price payable to SCs for Regulation made available for upward and downward movement in accordance with the ISO's Ancillary Services schedules will, for each Generating Unit, System Unit, and System Resource concerned, be the Zonal Market Clearing Price for Regulation calculated as follows:

$Pagc_{ijt} = MCP_{xt}$

where:

the Zonal Market Clearing Price (MCP_{xt}) for Regulation is the highest priced winning reservation bid of a Generating Unit, System Unit, or System Resource serving Demand in Zone X based on the reservation bid price (i.e., $MCP_{xt} = Max\ (CapRes_{ijt})$ in Zone X for Settlement Period t). In the absence of Inter-Zonal Congestion, the Zonal Market Clearing Prices will be equal.

SP 9.6 Spinning Reserves Bid Evaluation and Pricing

SP 9.6.1 Spinning Reserves Bid Evaluation

(a) Based on the quantity and location of the system requirements, the ISO will select the Generating Units, System Units and external imports of System Resources with the Spinning Reserve bids which minimize the sum of the total Spinning Reserve bids of the Generating Units, System Units and external imports of System Resources selected subject to two constraints:

(i) the sum of the selected amounts of Spinning Reserve bid must be greater than or equal to the required amount of Spinning Reserve; and

(ii) the amount of Spinning Reserve bid for each Generating Unit, System Unit or external import of a System Resource must be less than or equal to that Generating Unit's, System Unit's ramp rate times 10 minutes.

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

$$Min \sum_{i,j} Totalbid_{ijt}$$

subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

and

$$Cap_{ijt} \leq Cap_{ijt}max$$

where:

$TotalBid_{ijt}$ = $Cap_{ijt} * CapRes_{ijt}$

Requirement = *Amount of Spinning Reserve required by the ISO.*

SP 9.6.2 Spinning Reserves Price Determination

The price payable to SCs for Spinning Reserve made available in accordance with the ISO's Ancillary Services schedules shall, for each Generating Unit, System Unit or external import of a System Resource concerned, be the Zonal Market Clearing Price for Spinning Reserve calculated as follows:

$Psp_{ijt} = MCP_{xt}$

where:

the Zonal Market Clearing Price (MCP_{xt}) for Spinning Reserve is the highest priced winning reservation bid of a Generating Unit, System Unit or external import of a System Resource serving Demand in Zone X based on the reservation bid price (i.e., $MCP_{xt} = Max(CapRes_{ijt})$ in Zone *X* for Settlement Period t). In the absence of Inter-Zonal Congestion, the Zonal Market Clearing Prices will be equal.

SP 9.7 Non-Spinning Reserves Bid Evaluation and Pricing

SP 9.7.1 Non-Spinning Reserves Bid Evaluation

(a) Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units, Curtailable Demands and external imports of System Resources with the Non-Spinning Reserve bids which minimize the sum of the total Non-Spinning Reserve bids of the Generating Units, System Units, Curtailable Demands and external imports of System Resources selected subject to two constraints:

(i) the sum of the selected amounts of Non-Spinning Reserve bid must be greater than or equal to the required amount of Non-Spinning Reserve; and

(ii) the amount of Non-Spinning Reserve bid for each Generating Unit, System Unit, or Curtailable Demand must be less than or equal to that Generating Unit's, System Unit's, Curtailable Demand'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 to interruption in the case of a Load.

(b) The total Non-Spinning Reserve bid for each Generating Unit, System Unit, Curtailable Demand or external import of a System Resource is calculated by multiplying the reserve reservation bid price by the amount of Non-Spinning Reserve bid. Subject to any locational requirements, the ISO will accept the winning Non-Spinning Reserve bids in accordance with the following criteria:

$$Min\sum_{i,j} Totalbid_{ijt}$$

subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

and

$$Cap_{ijt} \leq Cap_{ijt}max$$

where:

$TotalBid_{ijt}$ = $Cap_{ijt} * CapRes_{ijt}$

Requirement = *Amount of Non-Spinning Reserve required by the ISO.*

SP 9.7.2 Non-Spinning Reserves Price Determination

The price payable to SCs for Non-Spinning Reserve made available in accordance with the ISO's Ancillary Services schedules shall, for each Generating Unit, System Unit, Curtailable Demand or external import of a System Resource concerned, be the Zonal Market Clearing Price for Non-Spinning Reserve calculated as follows:

$Pnonsp_{ijt} = MCP_x$

where:

the Zonal Market Clearing Price (MCP_{xt}) for Non-Spinning Reserve is the highest priced winning reservation bid of a Generating Unit, System Unit, Curtailable Demand or external import of a System Resource serving Demand in Zone X based on the reservation bid (i.e., $MCP_{xt} = Max(CapRes_{ijt})$ in Zone X for Settlement Period t). In the absence of Inter-Zonal Congestion, the Zonal Market Clearing Prices will be equal.

SP 9.8 Replacement Reserves Bid Evaluation and Pricing

SP 9.8.1 Replacement Reserves Bid Evaluation

(a) Based on the quantity and location of the system requirements, the ISO shall select the Generating Units, System Units, Curtailable Demands and external imports of System Resources with the Replacement Reserve bids which minimize the sum of the total Replacement Reserve bids of the Generating Units, System Units, Curtailable Demands and external imports of System Resources selected subject to two constraints:

(i) the sum of the selected amounts of Replacement Reserve bid must be greater than or equal to the required amount of Replacement Reserve; and

(ii) the amount of Replacement Reserve bid for each Generating Unit, System Unit, Curtailable Demand or external import of a System Resource must be less than or equal to that Generating Unit's, System Unit's, Curtailable Demand'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 to interruption in the case of Load.

(b) The total Replacement Reserve bid for each Generating Unit, System Unit, Curtailable Demand or external import of a System Resource is calculated by multiplying the reserve reservation bid price by the amount of Replacement Reserve bid. Subject to any locational requirements, the ISO will select the winning Replacement Reserve bids in accordance with the following criteria:

$$Min \sum_{i,j} Totalbid_{ijt}$$

subject to

$$\sum_{i,j} Cap_{ijt} \geq Requirement_t$$

and

$$Cap_{ijt} \leq Cap_{ijt} max$$

where:

$TotalBid_{ijt}$	=	$Cap_{ijt} * CapRes_{ijt}$
Requirement	=	*Amount of Replacement Reserve required by the ISO.*

SP 9.8.2 Replacement Reserves Price Determination

The price payable to SCs for Replacement Reserve made available in accordance with the ISO's Ancillary Services schedules shall, for each Generating Unit, System Unit, Curtailable Demand or external import of a System Resource concerned, be the Zonal Market Clearing Price for Replacement Reserve calculated as follows:

$Prepres_{ijt} = MCP_{xt}$

where:

the Zonal Market Clearing Price (MCP_{xt}) for Replacement Reserve is the highest priced winning reservation bid of a Generating Unit, System Unit, Curtailable Demand or external import of a System Resource serving Demand in Zone X based on the reservation bid price (i.e., $MCP_{xt} = Max(CapRes_{ijt})$ in Zone X for Settlement Period t). In the absence of Inter-Zonal Congestion, the Zonal Market Clearing Prices will be equal.

SP 9.9 Existing Contracts – Ancillary Services Accountability

Certain Existing Contracts may have requirements for Ancillary Services which differ from the requirements of this SP 9. Each PTO will be responsible for recovering any deficits or crediting any surpluses associated with differences in assignment of Ancillary Services requirements, through its bilateral arrangements or its Transmission Owner's Tariff. The ISO will not undertake the settlement or billing of any such differences under any Existing Contract.

SP 10 DAY/HOUR-AHEAD INTER-ZONAL CONGESTION MANAGEMENT

SP 10.1 Congestion Management Assumptions

The Inter-Zonal Congestion Management process is based upon the following assumptions:

(a) Inter-Zonal Congestion Management will ignore Intra-Zonal Congestion. Intra-Zonal Congestion will be managed in accordance with Tariff Section 7.2.6;

(b) Inter-Zonal Congestion Management will use a DC optimal power flow (OPF) program that uses linear optimization techniques with active power (MW) controls only; and

(c) transmission capacity reserved under Existing Contracts will not be subject to the ISO's Congestion Management procedures.

SP 10.2 Congestion Management Process

(a) 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. See the SBP for a general description of the use of Adjustment Bids to establish priorities.

(b) Inter-Zonal Congestion Management will not involve arranging or modifying trades between SCs. Each SC'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.

(c) Inter-Zonal Congestion Management will also not involve the optimization of SC portfolios within Zones (where such apparently non-optimal Schedules are submitted by SCs). Adjustments to individual SC 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.

(d) If Adjustment Bids are exhausted before Congestion is eliminated, the remaining Schedules will be adjusted *pro rata* except for those uses of transmission service under Existing Contracts, which are curtailed in accordance with SP 7.3 and SP 7.4.

SP 10.3 Congestion Management Pricing

(a) The Adjustment Bids that the SCs submit constitute implicit bids for transmission between Zones on either side of a Congested Inter-Zonal Interface. The ISO's Inter-Zonal

Congestion Management process will allocate Congested transmission to those users who value it the most and will charge all SCs for their allocated usage of Congested Inter-Zonal Interfaces on a comparable basis. All SCs 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.

(b) The ISO will determine the prices for the use of Congested Inter-Zonal Interfaces using the Adjustment Bids. The ISO will collect Usage Charges from SCs 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 7.3.1.3 of the ISO Tariff.

(c) The ISO will rebate the Congestion revenues collected through the Usage Charges to the PTOs which own the Congested Inter-Zonal Interface in proportion to their respective ownership rights.

SP 11 CREATION OF THE REAL-TIME MERIT ORDER STACK

SP 11.1 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 submitted in accordance with the SBP;

(b) Ancillary Services Energy Bids (except for Regulation) submitted for specific Ancillary Services in accordance with the SBP 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 in accordance with the SBP for those resources which SCs have elected to use to self-provide such specific Ancillary Services and for which the ISO has accepted such self-provision.

SP 11.2 Stacking of the Energy Bids

The sources of Imbalance Energy described in SP 11.1 will be arranged in order of increasing Energy Bid prices to create a merit order stack for use in accordance with the DP. 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 BEEP (Balancing Energy and Ex-Post Pricing) software.

Where, in any Settlement Period, the highest decremental Energy Bid in the merit order stack is higher than the lowest incremental Energy Bid, the BEEP software will eliminate the overlap by determining a target price for all those incremental and decremental bids which fall within the overlap. All decremental Energy Bids higher than the target price will be decreased to the target price. All incremental Energy Bids lower than the target price will be increased to the target price.

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.

SP 11.3 Use of the Merit Order Stack

The merit order stack, as described in SP 11.2, 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.

SP 12 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

SETTLEMENT AND BILLING PROTOCOL

SETTLEMENT AND BILLING PROTOCOL

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SETTLEMENT AND BILLING PROTOCOL (SABP)

SABP 1 OBJECTIVES, DEFINITIONS AND SCOPE

SABP 1.1 Objectives

The objective of this Protocol (and of Annex 1) is to inform Scheduling Coordinators, Participating TOs, Utility Distribution Companies, Metered Subsystems, and Operators of Reliability Must-Run Units of the manner in which the charges referred to in Section 11.1.6 of the ISO Tariff shall be calculated and settled and of the procedures regarding the billing, invoicing and payment of these charges.

SABP 1.2 Definitions

SABP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section is to a Section of the ISO Tariff. References to SABP are to this Protocol or to the stated paragraph of this Protocol. References to Annex 1 are to Annex 1 of this Protocol.

SABP 1.2.2 Special Definitions for this Protocol

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

"Day 0" means 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.

"Fed-Wire" means the Federal Reserve Transfer System for electronic funds transfer.

"Interim Black Start Agreement" means 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).

"ISO Surplus Account" means the account established by the ISO pursuant to SABP 6.5.

"Security" means the form of security provided by a Scheduling Coordinator pursuant to Section 2.2.3.2 of the ISO Tariff (i.e. letter of credit, guarantee or cash deposit) to secure its trading obligations.

"Trading Interval" means a Settlement Period as defined in the Master Definitions Supplement of the ISO Tariff.

SABP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol 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 Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

(e) A reference to a day or Trading Day is to a calendar day unless otherwise specified.

SABP 1.2.4 Time

All references to time are references to prevailing Pacific Time.

SABP 1.2.5 Financial Transaction Conventions

In this Protocol and its Appendices and Annex 1, 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 Protocol, this is defined as a "Charge";

(b) where the ISO is to required to pay a sum of money under this Protocol, this is defined as a "Payment".

SABP 1.2.6 Currency

All financial transactions are denominated in US dollars and cents.

SABP 1.3 Scope

SABP 1.3.1 Scope of Application to Parties

This Protocol (excluding Annex 1) applies to the ISO and to the following entities:

(a) Scheduling Coordinators;

(b) Participating TOs;

(c) Black Start Generators;

(d) Utility Distribution Companies, and

(e) Metered Subsystems.

The Settlement, billing and payment process between the ISO, Scheduling Coordinators, Participating TOs, Black Start Generators, Utility Distribution Companies, and Metered Subsystems shall be in accordance with Sections 11.3 to 11.24 inclusive of the ISO Tariff. References in those Sections to Scheduling Coordinators shall also apply to Participating TOs which receive Settlement Statements from the ISO in relation to the transactions referred to in those Settlement Statements but excluding the transactions referred to in Annex 1. Notwithstanding SABP 1.2.3(a), references in Sections 11.3 to 11.24 inclusive of the ISO Tariff to Scheduling Coordinators, ISO Debtors and ISO Creditors shall also apply to Black Start Generators which receive Settlement Statements from the ISO in relation to transactions under their Interim Black Start Agreements.

Annex 1 of this Protocol applies to the ISO, Owners of Reliability Must-Run Units and Participating TOs in relation to the billing and payment of amounts due under Reliability Must-Run Contracts and recovery of such amounts by the ISO from Participating Utilities. The provisions of this Protocol shall not apply to Annex 1 unless otherwise specified.

SABP 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.

SABP 2 OVERVIEW OF SETTLEMENT AND BILLING PROCESS

SABP 2.1 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 this Protocol and 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 and this Protocol. Nothing in this section will be deemed to establish the burden of proof with respect to Settlement calculations in any proceeding.

SABP 2.2 ISO Accounts

SABP 2.2.1 Costs Associated with the ISO Trust Accounts

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 Protocol the ISO will recover all costs incurred in connection with these ISO banking facilities through the appropriate component of the Grid Management Charge.

SABP 2.2.2 Location of the ISO Accounts

The ISO will maintain its bank accounts held on trust at a bank in California approved by the ISO Governing Board.

SABP 2.2.3 ISO Trust Accounts

The ISO will open and operate the following accounts which it will hold on trust for Market Participants:

(a) the ISO Clearing Account to and from which payments are made pursuant to Section 11.8.2.1 of the ISO Tariff and SABP 6.3.1;

(b) the ISO Reserve Account from which any debit balances on the ISO Clearing Account at the close of banking business are settled pursuant to Section 11.8.2.2 of the ISO Tariff and SABP 6.4; and

(c) the ISO Surplus Account consistent with Section 11.8.2.3 of the ISO Tariff and SABP 6.5.

The ISO may establish additional trust accounts as necessary to implement the Settlement and billing procedures outlined in this Protocol. It shall notify the Market Participants of the establishment of such accounts through the WEnet.

SABP 2.2.4 The ISO Clearing Account

Subject to SABP 6.1.2, ISO Debtors shall make all payments of ISO invoices by Fed-Wire to the ISO Clearing Account by 10:00 am on the due date according to the ISO Payments Calendar.

SABP 2.2.5 The ISO Reserve Account

The ISO shall operate the ISO Reserve Account as a trust account as follows:

(a) 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;

(b) if the Reserve Account is replenished as provided for in SABP 6.9, any credits shall be held on trust for all ISO Creditors.

SABP 2.2.6 Accounts of the SCs 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 Protocol. 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 SC 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.

SABP 2.3 ISO Payments Calendar

SABP 2.3.1 Contents of ISO Payments Calendar

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 SABP 4.4.1 and the ISO Tariff;

(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 Annex 1.

SABP 2.3.2 Calendar Content and Format

In accordance with SABP 2.3.3, 2.3.4 and 2.3.5 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.

SABP 2.3.3 Draft Payments Calendar

In September of each year, 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.

SABP 2.3.4 Final Payments Calendar

No later than October 31st in each year, the ISO will publish pursuant to Section 11.24.1 of the ISO Tariff 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.

SABP 2.3.5 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 SABP 2.3.3 and 2.3.4 above 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.

SABP 2.3.6 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.

SABP 3 COMPUTATION OF CHARGES

SABP 3.1 Description of Charges to be Settled

The ISO shall, 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, calculate the following:

(a) the amount due from each Scheduling Coordinator for its share for the relevant month of the seven components of the Grid Management Charge in accordance with the formula located in Appendix F, Schedule 1, Part A of this Tariff. These Charges shall accrue on a monthly basis.

(b) the amount due from each Scheduling Coordinator for the Grid Operations Charge in accordance with Appendix F, Schedule 2 of this Tariff. This charge shall accrue on a monthly basis.

(c) the amount due from and/or owed to each Scheduling Coordinator for the Charge for each Ancillary Service in accordance with Appendix C, for each of the Settlement Periods of Day 0.

(d) the amount due from and/or owed to each Scheduling Coordinator for Imbalance Energy in accordance with Appendix D, for each of the Settlement Periods of Day 0.

(e) the amount due from and/or owed to each Scheduling Coordinator for Usage Charges in accordance with Appendix E, for each of the Settlement Periods of Day 0.

(f) the amount due from each Scheduling Coordinator for Wheeling Out and Wheeling Through Charges and the amount owed to each Participating TO for these charges in accordance with Appendix F, for each of the Settlement Periods of Day 0.

(g) the amounts due from/to Scheduling Coordinators for Voltage Support (supplemental reactive power charges) for each of the Settlement Periods of Day 0 in accordance with Appendix G.

(h) the monthly charges due from/to Scheduling Coordinators for long-term Voltage Support provided by Owners of Reliability Must-Run Units in accordance with Appendix G.

(i) the amounts due from/to Scheduling Coordinators for the provision of Black Start Energy from Reliability Must-Run Units for each of the Settlement Periods of Day 0 in accordance with Appendix G.

(j) the amounts due from/to Black Start Generators for the provision of Black Start Energy for each of the Settlement Periods of Day 0 in accordance with Appendix G.

(k) 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.

(l) the amounts due from Scheduling Coordinators for FERC Annual Charges.

All of the data, information, and estimates the ISO uses to calculate these amounts shall be subject to the auditing requirements of Section 10.5 of the ISO Tariff.

The ISO shall calculate these amounts using the software referred to in SABP 2.1 except in cases of system breakdown when it shall apply the procedures set out in SABP 9 (Emergency Procedures).

SABP 3.1.1 Additional Charges and Payments

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 respect of penalties 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; and

(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 2.5.27.1 of the ISO Tariff. 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 for that Trading Day.

SABP 3.2 Method of Settlement of Charges

SABP 3.2.1 Settlement of Payments to/from Scheduling Coordinators and Participating TOs

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 as provided in SABP 4.

The seven 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 SABP 3.1, but a separate invoice for the Grid Management Charge, stating the rate, billing determinant volume, and total charge for each of its seven components, will be issued by the ISO to the Scheduling Coordinator.

SABP 4 SETTLEMENT STATEMENTS

SABP 4.1 Preliminary Settlement Statements

SABP 4.1.1 Timing of Preliminary Settlement 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 in accordance with the ISO Payments Calendar.

SABP 4.1.2 Contents of Preliminary Settlement Statements

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 SABP 3 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 SABP 3.2.1; and

(c) the components of each charge in each Settlement Period except for information contained in the Imbalance Energy Report referred to in SABP 4.1.3.

SABP 4.1.3 Imbalance Energy Report

Each Preliminary Settlement Statement shall be accompanied by a breakdown of the components of the Imbalance Energy Charge (the "Imbalance Energy Report").

SABP 4.2 Final Settlement 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 set forth in SABP 4.3 and 4.4.

SABP 4.3 Review, Validation, Confirmation of Preliminary Settlement Statements

The provisions for confirmation, review and validation of Preliminary Settlement Statements set forth in Sections 11.6.1.2, 11.7.1, 11.7.2, 11.7.3 and 11.7.4 of the ISO Tariff shall apply to all Scheduling Coordinators, Black Start Generators or Participating TOs (save, in the case of Participating TOs, for charges or rebates referred to in Annex 1) who receive a Preliminary Settlement Statement from the ISO.

SABP 4.4 Resolving Disputes Relating to Preliminary and Final Settlement Statements

SABP 4.4.1 Notice

SABP 4.4.1.1 Notice of an ordinary dispute

If a Scheduling Coordinator, Black Start Generator or Participating TO disputes any item or calculation set forth in its Preliminary or Final Settlement, it shall provide the ISO by electronic means with a notice of dispute within eight (8) Business Days from the date of issue of the Preliminary Settlement Statement or within ten (10) Business Days from the date of issue of the Final Settlement Statement.

SABP 4.4.1.2 Notice of recurring dispute

If a Scheduling Coordinator, Black Start Generator or Participating TO believes a dispute will apply to subsequent Preliminary or Final Settlement Statements, it may request, in a notice provided in accordance with Section SABP 4.4.1.1 above, that the ISO treat the dispute as recurring. 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.

SABP 4.4.2 Contents of Notice

SABP 4.4.2.1 Contents of a notice of dispute

The notice of dispute shall state clearly the Trading Day, the issue date of the Preliminary of 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.

SABP 4.4.2.2 Contents of a request for treatment as a recurring dispute

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 provided in accordance with Section SABP 4.4.2.1 above, 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.

SABP 4.4.3 ISO determination of a recurring dispute

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.

SABP 4.4.4 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.

SABP 4.4.5 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.

SABP 4.4.6 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.

SABP 4.5 Settlement Statement Re-runs

SABP 4.5.1 Notice

If a Scheduling Coordinator, Black Start Generator or Participating TO, (having made reasonable efforts to resolve with the ISO any dispute relating to a Preliminary Settlement Statement pursuant to SABP 4.4) requires a Settlement Statement Re-run, it shall send at any time to the ISO Governing Board a notice in writing.

SABP 4.5.2 ISO Tariff

The provisions of Sections 11.6.3, 11.6.3.1, 11.6.3.2 and 11.6.3.3 of the ISO Tariff relating to Settlement Statement Re-runs shall apply to all Scheduling Coordinators, Black Start Generators or Participating TOs who require a Settlement Re-run in accordance with this SABP 4.5.

SABP 5 INVOICES

The ISO shall provide on the day specified in the ISO Payments Calendar an invoice in the format set out in SABP Appendix I showing:

(a) amounts which according to each of the Preliminary and Final Settlement Statements of that Billing Period are to be paid from or to each Scheduling Coordinator, Black Start Generator or Participating TO;

(b) the Payment Date, being the date on which such amounts are to be paid or received and the time for such payment; and

(c) details (including the account number, bank name and Fed-Wire transfer instructions) of the ISO Clearing Account to which any amounts owed by the Scheduling Coordinator, 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 seven 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.

SABP 6 PAYMENT PROCEDURES

SABP 6.1 Time of Payment

SABP 6.1.1 Payment Date

Subject to SABP 6.1.2, payment will be made by the ISO and by each Scheduling Coordinator, Black Start Generator and Participating TO on the Payment Date as set forth in Section 11.3.2. Payment will be made by the ISO in accordance with Section 11.13.

SABP 6.1.2 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 Protocol.

SABP 6.2 Payments to be made by Fed-Wire

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.

SABP 6.3 Payment Process

SABP 6.3.1 Use of the ISO Clearing Account

(a) Subject to SABP 6.1.2 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 SABP 6.1.2(c).

SABP 6.3.1.2 Distribution to ISO Creditors

The ISO shall calculate the amounts available for distribution to ISO Creditors on the Payment Date specified in Section 11.13 and shall give irrevocable instructions to the ISO Bank to remit from the ISO Clearing Account to the relevant Settlement Account maintained by each ISO Creditor for same day value the amounts determined by the ISO to be available for payment to each ISO Creditor. 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 by the close of banking business on the Payment Date.

SABP 6.3.1.3 Grid Management Charge

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.

SABP 6.4 Use of the ISO Reserve Account

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 SABP 6.7.2.

SABP 6.5 Use of the ISO Surplus Account

SABP 6.5.1 Establishment

The ISO shall establish and maintain a bank account in accordance with this Protocol denominated the "ISO Surplus Account".

SABP 6.5.2 Other Funds Used in the ISO Surplus Account.

(a) Any amounts paid to the ISO in respect of penalties referred to in SABP 3.1.1 shall be credited to the Surplus Account.

(b) The funds referred to in SABP 6.5.2(a) pertaining to Penalties as provided in SABP 3.1.1 shall first be applied towards any expenses, loss or costs incurred by the ISO. Any excess will be credited to the Surplus Account pursuant to SABP 6.5.2(a).

(c) The funds referred to in SABP 6.5.2(a) pertaining to default Interest referred to in SABP 6.10.5 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 SABP 6.5.2(a).

SABP 6.5.3 Distribution of Funds

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.

SABP 6.5.4 Trust

All amounts standing to the credit of the ISO Surplus Account will be held at all times on trust for Market Participants in accordance with this Protocol.

SABP 6.6 System Failure

SABP 6.6.1 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.

SABP 6.6.2 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.

SABP 6.7 Payment Default

Subject to SABP 6.8, 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:

SABP 6.7.1 Enforcing the Security of a Defaulting Scheduling Coordinator

Subject to SABP 6.8 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 SABP 6.7.2 or 6.7.4 as applicable.

SABP 6.7.2 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 SABP 2.2.5) 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.

SABP 6.7.3 Action against a Defaulting Scheduling Coordinator

The ISO shall as soon as possible after taking action under SABP 6.7.2 take any steps it deems appropriate against the defaulting Scheduling Coordinator to recover the Default Amount (and any Interest as set out in SABP 6.10.5) including enforcing any Security pursuant to Section 11.14 of the ISO Tariff, exercising its rights of recoupment or set-off pursuant to SABP 6.10.2 and/or bringing proceedings against the defaulting Scheduling Coordinator pursuant to Section 11.20.1 of the ISO Tariff.

SABP 6.7.4 Reduction of Payments to ISO Creditors

If there are insufficient funds standing to the credit of the ISO Reserve Account, the ISO shall reduce payments to ISO Creditors on that Payment Date pursuant to Section 11.16.1 of the ISO Tariff to the extent necessary to clear the ISO Clearing Account by the close of banking business on the Payment Date.

SABP 6.8 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 SABP 6.10.5.

SABP 6.9 Replenishing the ISO Reserve Account Following Payment Default

If the ISO has debited the ISO Reserve Account as provided in SABP 6.7.2 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 referred to in SABP 6.8.2 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 referred to in SABP 6.10.5 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.

SABP 6.10 Application of Funds Received

Amounts credited to the ISO Clearing Account in payment of a Default Amount (as set out in SABP 6.9(a)) or as a result of enforcing the defaulting ISO Debtor's Security shall be applied to the ISO Reserve Account pursuant to SABP 6.9 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 SABP 6.7.4.

SABP 6.10.1 Termination of SC Agreement and Limitation on Trading

The provisions of Section 2.2.4.5 and 2.2.7.3 of the ISO Tariff shall apply.

SABP 6.10.2 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 SABP 6.10.4 unless otherwise specified in accordance with Section 11.16.

SABP 6.10.3 Defaulting SCs and Eligible Customers

If the ISO intends to terminate the SC Agreement of a Scheduling Coordinator (the "Defaulting SC") pursuant to Section 2.2.4.5 of the ISO Tariff, the ISO shall give written notice to the UDC or UDCs on whose service territory the customers of that Defaulting SC are located and shall post such notification on the ISO Home Page pursuant to Section 2.2.4.6 of the ISO Tariff.

SABP 6.10.4 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.

SABP 6.10.5 Interest on Defaulted Payments

Unless the ISO is able to enforce the Security (if any) provided by the defaulting ISO Debtor, such ISO Debtor shall pay Interest on the Default Amount for the period from the relevant Payment Date to the date on which the payment is received by the ISO together with any related transaction costs incurred by the ISO pursuant to SABP 6.7.2.

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.

SABP 6.10.6 Interest Accruing while Enforcing the Security

If the ISO has debited the Reserve Account as provided in SABP 6.7.1, 6.7.2 or 6.8 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.

SABP 7 PAYMENT ERRORS

SABP 7.1 Overpayments

SABP 7.1.1 Notification

If an ISO Creditor receives an overpayment on any Payment Date, it shall notify the ISO of such overpayment in accordance with the provisions of Section 11.18.1 of the ISO Tariff.

SABP 7.1.2 Overpayment held on 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.

SABP 7.1.3 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 SABP 6.7 will apply.

SABP 7.1.4 Treatment of Amounts Outstanding as a Result of an Overpayment

The ISO shall apply the amount of any overpayment repaid (including interest received) to it under SABP 7.1.3 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.

SABP 8 COMMUNICATIONS

SABP 8.1 Method of Communication

Preliminary Settlement Statements and Final Settlement Statements will be published by the ISO on the WEnet. Invoices will be issued via EDI. Communications on a Payment Date relating to payment shall be made by the fastest practical means including by telephone. 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.

SABP 8.2 Failure of Communications

The provisions of Section 11.23 of the ISO Tariff shall apply.

SABP 9 EMERGENCY PROCEDURES

SABP 9.1 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 or this Protocol. Details of the variation and the method chosen to produce estimated data, Settlement Statements and invoices will be published on the ISO Home Page.

SABP 9.2 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 under SABP.

SABP 9.3 Validation and Correction of Estimated Statements and Invoices

The ISO shall use its best efforts to verify the estimated data used under SABP 9.1 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 in the manner set forth in Section 11.5 of the ISO Tariff.

SABP 9.4 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 SABP 4.4.5 shall apply to payment of revised invoices issued in accordance with this SABP 9.4. Failure to make payments of such revised invoices shall result in the same consequences as a failure to make actual payments under SABP.

SABP 10 CONFIDENTIAL DATA

(a) The ISO shall implement and maintain a system of communication with Scheduling Coordinators to ensure compliance with Sections 11.22 and 20.3 of the ISO Tariff regarding access to confidential data and with Participating TOs pursuant to Section 26.3 of the Transmission Control Agreement.

(b) 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.

SABP 11 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

SETTLEMENT AND BILLING PROTOCOL

APPENDICES A-I

APPENDIX A

[Not Used]

APPENDIX 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 7.3.2 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 SCs 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 Day-Ahead or Hour-Ahead Adjustment Bid (or Imbalance Energy bid as appropriate) 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 Adjustment 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 Adjustment Bid curve (or 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 7.2.6.1 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$_i$, Adjustment Bid curve, 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:

$$GOC_{jt} = GOP_t * \left(QCharge_{jt} + EXPORT_{jt}\right)$$

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 Adjustment Bid curve (or 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 Day-Ahead or Hour-Ahead Adjustment Bid curve (or Imbalance Energy bid) submitted by the Scheduling Coordinator$_j$ or generated by the ISO for the Trading Interval$_t$.

B 3.3 ∆incbijt - 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 Adjustment Bid curve (or Imbalance Energy bid).

B 3.4 PayTI$_{jit}$ - $

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 Adjustment Bid curve (or 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 of the Day-Ahead or Hour-Ahead Adjustment Bid curve (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_{bijt} - 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 of the Adjustment Bid curve (or Imbalance Energy bid) for System $Resource_i$.

B 3.8 **$ChargeTI_{ijt}$ - $**

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 **$REDISP_{CONGt}$ - $**

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 $Coordinator_j$.

APPENDIX 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 Appendix C to the Ancillary Service "Regulation" shall be read as referring to "Regulation Up" or "Regulation Down".

This Appendix 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 Appendix D of this Protocol.

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 the Ancillary Services Requirements Protocol. 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 the Ancillary Services Requirements Protocol. 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 the Ancillary Services Requirements Protocol. 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:

$$NonSpinPayDA_{ijxt} = NonSpinQDA_{ijxt} * PNonSpinDA_{xt}$$

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:

$$NonSpinPayTotalDA_{jxt} = \sum_{i} NonSpinPayDA_{ijxt}$$

(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 thatTrading Interval in that Zone. The required Replacement Reserve capacity is defined in the Ancillary Services Requirements Protocol. 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 the Ancillary Services Requirements Protocol. 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:

$$AGCUpPayTotalHA_{jxt} = \sum_i AGCUpPayHA_{ijxt} - \sum_i AGCUpReceiveHA_{ijxt}$$

$$AGCDownPayTotalHA_{jxt} = \sum_i AGCDownPayHA_{ijxt} - \sum_i AGCDownReceiveHA_{ijxt}$$

(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) <u>*Replacement Reserve*</u>. 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,

$AGCUpPayTotalDA_{ixt}$ = 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) *<u>Regulation</u>.* 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,

$AGCUpPayTotalHa_{jxt}$= Totlal 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,

$AGCDownPayTotalHA_{xt}$ = 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 2.5.3.6.

$OrigReplReqHA_{xt}$ = 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 2.5.3.

$PRepResDA_{xt}$ 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:

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

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 I in Zone x during Settlement Period t as referenced in SABP Appendix D.

$LoadDev_{ijxt}$ = The deviation between scheduled and actual Load consumption for resource I represented by Scheduling Coordinator iin Zone x during Settlement Period t as referenced in SABP Appendix 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.

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

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 2.5.3.6 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 decrmental 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 accordnace with Section 2.5.27.1 of the ISO Tariff, in accordance with SABP 3.1.1(d)

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 2.5.21, 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 2.5.21, the bid price for the unit for Regulation Down Capacity in Zone x for Trading Interval t.

C 3.4 **$AGCUpPayTotalDA_{jxt}$ - $**

The total payment for Regulation Up capacity to Scheduling Coordinator j in the Day-Ahead Market in Zone x for Trading Interval t.

$AGCDownPayTotalDA_{jxt}$ - $

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 **$AGCUpPayHA_{ijxt}$ - $**

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.

$AGCDownPayHA_{ijxt}$ - $

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 **$AGCUpReceiveHA_{ijxt}$ - $**

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.

$AGCDownReceiveHA_{ijxt}$ - $

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 **$AGCUpQIHA_{ijxt}$ – 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.

$AGCDownQIHA_{ijxt}$ – 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 theISO 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 the Ancillary Services Requirements Protocol. 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 the Ancillary Services Requirements Protocol. 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 the Ancillary Services Requirements Protocol. 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 the Ancillary Services Requirements Protocol. 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 **$AGCUpChgHA_{jxt}$ - $**

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.

$AGCDownChgHA_{jxt}$ - $

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 **$EnQPay_{ijxt}$ - $**

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 **$SpinPayDA_{ijxt}$ - $**

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 **$SpinQDA_{ijxt}$ – 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 **$REPA_{ijxt}$ - $**

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 **RUP_{ijxt} – 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 **RDN_{ijxt} – 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 2.5.21, 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$_{ijxt}$ - $**

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$_{Ijxt}$ - $**

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 **SpinQIHA$_{ijxt}$ – 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 the Ancillary Services Requirements Protocol. 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 the Ancillary Services Requirements Protocol. 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 2.5.21, 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 **NonSpinQIHA$_{ijxt}$ – 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 **NonSpinQDHA$_{ijxt}$ – 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 **PNonSpinHA$_{xt}$ - $/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 **NonSpinPayTotalHA$_{jxt}$ - $**

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 **NonSpinRateDA$_{xt}$ - $/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 **$NonSpinObligTotal_{xt}$ – MW**

The net total Non-Spinning Reserve capacity obligation in Zone x for Trading Interval t as defined in the Ancillary Services Requirements Protocol. This net total obligation equals the total minus that self-provided.

C 3.43 **$NonSpinChgDA_{jxt}$ - $**

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 **$NonSpinOblig_{jxt}$ – MW**

The net Non-Spinning Reserve capacity obligation for Scheduling Coordinator j in Zone x for Trading Interval t as defined in the Ancillary Services Requirements Protocol. 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 the Ancillary Services Requirements Protocol. 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 2.5.21, 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 **$ReplPayTotalHA_{jxt}$ - $**

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 **$ReplChgDA_{jxt}$ - \$**

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 the Ancillary Services Requirements Protocol. 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 undispatched 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 the Ancillary Services Requirements Protocol.

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.

APPENDIX 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 Scheduling Coordinator in each Settlement Period in the relevant Zone 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 BEEP Interval of each Settlement Period calculated in accordance with the following formulae:

$$DevC = \sum_i GenDevC_i + \sum_i LoadDevC_i + \sum_q ImpDevC_q + \sum_q ExpDevC_q + UFEC$$

$$ASSEDevC = \sum_i ASSEGenDevC_i + \sum_i ASSELoadDevC_i + \sum_q ASSEImpDevC_q$$

$$DevC_{bjxt} = NetDev_{bjxt} * BIP_{bxt}$$

$$NetDev_{bjxt} = \begin{pmatrix} \sum_{i \in SC_j} GenDev_{bixt} - \sum_{i \in SC_j} LoadDev_{bixt} + \\ \sum_{q \in SC_j} ImpDev_{bqxt} - \sum_{q \in SC_j} ExpDev_{bqxt} \end{pmatrix}$$

Where P_{bxt} is the BEEP Interval Price for Imbalance Energy in Zone x during BEEP Interval b in Settlement Period t.

The deviation quantity between scheduled and actual Energy Generation for Generator i represented by Scheduling Coordinator j in Zone x during BEEP Interval b of Settlement Period t is calculated as follows:

$$GenDev_{bixt} = GenDev'_{bixt} + UnavailAncServMW_{bixt}$$
$$GenDev'_{bixt} = G_{s,bixt} * GMM_{f,ixt} - \left[\left(G_{a,bixt} - G_{\mathrm{adj},bixt}\right) * GMM_{a} - G_{\mathrm{a/s},bixt} - G_{\mathrm{s/e},bixt}\right]$$

Where:

If the BEEP Interval Ex Post Price is negative or zero, then:

$UnavailAncServMW_{bixt} = 0$

If the BEEP Interval Ex Post Price is positive, then:

$$UnavailAncServMW_{bixt} =$$
$$\max\left(0, \min\left(-GenDev'_{bixt}, G_{a,bixt} * GMM_{a,ixt} - \left[\frac{P_{\max,ixt}}{HBI} * GMM_{a,ixt} - \max\left(0, \frac{G_{\mathrm{oblig},ixt}}{HBI} - G_{\mathrm{a/s},bixt}\right)\right]\right)\right)$$

The value of $G_{a,bixt}$ for Generation scheduled on behalf of Participating Generators for each BEEP Interval in each Settlement Period shall be the actual meter data aggregated on a 10-minute basis. The value of $G_{s,bixt}$ for Generation scheduled on behalf of Participating Generators for each BEEP Interval in each Settlement Period shall be determined as follows for BEEP Intervals 2 through 5:

$$G_{s,bixt} = \frac{G_{s,ixt}}{HIB}$$

For BEEP Interval 1 and BEEP Interval 6, implicit Dispatch instructions for ramping will be applied to adjust the Schedules attributed to those BEEP Intervals as follows:

$$G_{s,6ixt} = \left(\frac{G_{s,ixt}}{HIB}\right) - \left(\frac{\left(G_{s,ixt+1} - G_{s,ixt}\right)}{4\,HIB}\right)$$

The value of $G_{s,bit}$ and $G_{a,bit}$ for Generation which has not undertaken in writing to be bound by the ISO Tariff in accordance with Article 5 shall be determined as follows for all six BEEP Intervals:

$$G_{s,bixt} = \frac{G_{s,ixt}}{HIB}$$

$$G_{a,bixt} = \frac{G_{a,ixt}}{HIB}$$

The deviation quantity between scheduled and actual Load consumption for Load i represented by Scheduling Coordinator j in Zone x during BEEP Interval b of Settlement Period t is calculated as follows:

$$LoadDev_{bixt} = LoadDev'_{bixt} - UnavailDispLoadMW_{bixt}$$
$$LoadDev'_{bixt} = L_{s,bixt} - \left(L_{a,bixt} - L_{\mathrm{adj},bixt} + L_{\mathrm{a/s},bixt} + L_{\mathrm{s/e},bixt}\right)$$

Where:

If the BEEP Interval Ex Post Price for decremental Energy is negative or zero, then:

$UnavailDispLoadMW_{bixt} = 0$

If the BEEP Interval Ex Post Price for Imbalance Energy is positive, then:

$$UnavailDispLoadMW_{bixt} =$$

$$\max\left(0, \min\left(LoadDev'_{bixt}, \max\left(0, \frac{L_{\text{oblig},ixt}}{HBI} - L_{\text{a/s},bixt}\right) - L_{a,bixt}\right)\right)$$

The value of $L_{a/s,bixt}$,$L_{s/e,bixt}$ and $L_{\text{adj},bixt}$ are determined on a 10-minute basis. The value of L_a for Load scheduled on behalf of Participating Loads for each BEEP Interval in each Settlement Period shall be the actual meter data aggregated on a 10-minute basis. The value of $L_{s,bixt}$ for Load scheduled on behalf of Participating Loads for each BEEP Interval in each Settlement Period t, shall be determined as follows:

For BEEP Intervals 2 through 5,

$$L_{s,bit} = \frac{L_{s,it}}{HIB}$$

For BEEP Interval 1 and BEEP Interval 6, implicit Dispatch instructions for ramping will be applied to adjust the schedules attributed to those BEEP Intervals as follows:

$$L_{s,1ixt} = \left(\frac{L_{s,ixt}}{HIB}\right) - \left(\frac{\left(L_{s,ixt} - L_{s,ixt-1}\right)}{4\,HIB}\right)$$

$$L_{s,6ixt} = \left(\frac{L_{s,ixt}}{6}\right) + \left(\frac{\left(L_{s,ixt+1} - L_{s,ixt}\right)}{4\,HIB}\right)$$

The value of $L_{s,bixt}$ and $L_{a,bixt}$ for Loads that are not Participating Loads shall be determined as follows for all six BEEP Intervals:

$$L_{s,bixt} = \frac{L_{s,ixt}}{HIB}$$

$$L_{a,bixt} = \frac{L_{a,ixt}}{HIB}$$

Where $L_{a,ix}$ is Load i hourly metered quantity for Settlement Period t.

The deviation quantity between forward scheduled and Real Time adjustments to Energy imports[*], adjusted for losses, for Scheduling

[*] Note that this deviation is a difference between a forward Market value and a Real Time value. It is not inadvertent energy.

Point q represented by Scheduling Coordinator j into Zone x during each BEEP Interval b of each Settlement Period t is calculated as follows:

$$ImpDev_{bqxt} = I_{s,bqxt} * GMM_{f,qxt} - \left(I_{a,bqxt} - I_{\mathrm{adj},bqxt} + I_{a/s,bqxt}\right) * GMM_{a,qxt} + I_{a/s,bqxt} * GMM_{a,qxt}$$

The values of $I_{a/s,bqxt}$, $I_{a,bqxt}$ and $I_{adj,bqxt}$ are determined on a 10-minute basis. The value of $I_{s,bqxt}$ in all BEEP Intervals shall be determined as follows:

$$I_{s,bqxt} = \frac{I_{s,qxt}}{HIB}$$

The deviation quantity between forward scheduled and Real Time adjustments to Energy exports* for Scheduling Point q represented by Scheduling Coordinator j from Zone x during BEEP Interval b for Settlement Period *t* is calculated as follows:

$$ExpDev_{bqxt} = E_{s,bqxt} - E_{a,bqxt} - E_{\mathrm{adj},bqxt}$$

The values of $E_{a,bqxt}$ and $E_{\mathrm{adj},bqxt}$ are determined on a 10-minute basis. The value of $E_{s,qit}$ in all BEEP Intervals shall be determined as follows:

$$E_{s,bqxt} = \frac{E_{s,qxt}}{HIB}$$

D 2.1.2 Instructed Imbalance Energy Charges on Scheduling Coordinators

Implicit Dispatch instructions for ramping Energy shall be calculated based on Final Hour Ahead Schedules for Energy to result in a linear ramp by all Participating Generators and Participating Loads beginning 10 minutes prior to the start, and ending 10 minutes after the start of each Settlement Period. Ramping Energy shall be deemed delivered and settled at a price of zero dollars per MWh.

The amount of Instructed Imbalance Energy to be delivered in each BEEP Interval will be determined based on the ramp rates and time delays bid in accordance with SBP 5 and 6 and shall be deemed delivered to the ISO Controlled Grid. Any excess delivery or shortfall will be accounted for as Uninstructed Imbalance Energy. Payment due a Load, Generator, Import or Export for Instructed Imbalance Energy to be delivered in a BEEP Interval shall be calculated based on the actual Energy delivered to the ISO Grid in accordance with the Dispatch instruction.

Instructed Imbalance Energy in each BEEP Interval shall be paid, if positive, or charged, if negative, the corresponding BEEP Interval Ex Post Price.

Due to ramp rate limitations, resources responding to Dispatch Instructions that revert partially or wholly Dispatch Instructions issued earlier within the same hour may generate or consume Instructed Imbalance Energy bid at prices higher or lower than the BEEP Interval Ex Post Price, respectively. This residual Instructed Imbalance Energy which may cross hourly boundaries, shall be priced based on the applicable BEEP Interval Ex Post Price for the BEEP Interval to which the original Dispatch instruction applied.

Subject to the above conditions, the Instructed Imbalance Energy charge for each BEEP Interval b of each Settlement Period t for Scheduling Coordinator j for Zone x is calculated using the following formulas:

The instructed Generation deviation payment/charge is calculated as follows:

$$IGDC_{ib} = G_{ib} * P_b$$

The instructed Load deviation payment/charge is calculated as follows:

$$ILDC_{bixt} = -\left(L_{a/s,bixt} + L_{se,bixt}\right) * P_{bxt}$$

The instructed import deviation payment/charge is calculated as follows:

$$IIDC_{bqxt} = -\left(I_{a/s,bqxt} + I_{se,bqxt}\right) * P_{bxt}$$

D 2.2 Unaccounted for Energy Charge

The Unaccounted for Energy Charge on Scheduling Coordinator j for each BEEP Interval b of each Settlement Period t for each relevant Zone is calculated in the following manner:

The UFE for each utility Service Area *k* for which separate UFE calculation is performed is calculated as follows,

$$UFE_{UDC,bkt} = \sum_{q \in UDC_k} I_{a,bqxt} - \sum_{q \in UDC_k} E_{a,bqxt} + \sum_{i \in UDC_k} G_{a,bixt} - \sum_{i \in UDC_k} L_{a,bixt} - TL_{bkt}$$

The Transmission Loss TL_{bkt} for BEEP Interval b of Settlement Period t for utility Service Area k is calculated as follows:

$$TL_{bkt} = \left(\sum_i \left[G_{a,bixt} * (1 - GMM_{a,ixt}) \right] + \sum_q \left[I_{a,bqxt} * (1 - GMM_{a,qxt}) \right] \right) * \frac{PFL_{kt}}{\sum_k PFL_{kt}}$$

Where PFL_{kt} are the Transmission Losses for utility Service Area k as calculated by a power flow solution for Settlement Period t, consistent with the calculation of final forecasted Generation Meter Multipliers.

Each metered demand point z in utility Service Area k, either ISO grid connected or connected through UDC k, is allocated a portion of the UFE as follows:

$$UFE_{bixt} = UFE_{UDC,bkt} * \frac{L_{bixt}}{\sum_{i \in UDC_k} L_{bixt}}$$

The UFE charge for Scheduling Coordinator j for BEEP Interval b of Settlement Period t in Zone x is calculated as follows:

$$UFEC_{jxt} = \left(\sum_{i \in SC_j} UFE_{bixt} \right) * P_{bxt}$$

D 2.3 Hourly Ex Post Price

The Hourly Ex Post Price in Zone x in Settlement Period t is determined as follows:

$$HP_{xt} = \frac{\sum_b \left| Q_{bxt} \right| P_{bxt}}{\sum_b \left| Q_{bxt} \right|}$$

Where Q_{bxt} is the total Instructed Imbalance Energy during BEEP Interval b in Zone x in Settlement Period t.

D 3 Meaning of terms in the formulae

D 3.1 $DevC_{bjxt}$ – $

The Uninstructed Imbalance Energy charge on Scheduling Coordinator j during BEEP Interval b in Settlement Period t in Zone x.

D 3.2 **$GenDev_{bixt}$ – MWh**

The deviation between scheduled and actual Energy Generation for Generator i in Zone x during BEEP Interval b in Settlement Period t.

D 3.3 **$LoadDev_{bixt}$ – MWh**

The deviation between scheduled and actual Load consumption for Load i in Zone x during BEEP Interval b in Settlement Period t.

D 3.4 **$ImpDev_{bqxt}$ – MWh**

The deviation between forward scheduled and Real Time adjustments to Energy imports, as adjusted for losses, for Scheduling Point q in Zone x during BEEP Interval b in Settlement Period t.

D 3.5 **$ExpDev_{bqxt}$ – MWh**

The deviation between forward scheduled and Real Time adjustments to Energy exports for Scheduling Point q in Zone x during BEEP Interval b in Settlement Period t.

D 3.6 **$G_{s,ixt}$ – MWh**

The scheduled Generation of Generator i in Zone x in Settlement Period t as a result of both the Day-Ahead Final Schedule and the Hour-Ahead Final Schedule.

D 3.6.1 **$G_{s,ixt-1}$ – MWh**

The scheduled Generation of Generator i in Zone x in Settlement Period t–1 as a result of both the Day-Ahead Final Schedule and the Hour-Ahead Final Schedule.

D 3.6.2 **$G_{s,ixt+1}$ – MWh**

The scheduled Generation of Generator i in Settlement Period t+1 as a result of both the Day-Ahead Final Schedule and the Hour-Ahead Final Schedule.

D 3.6.3 **$G_{adj,bixt}$ – MWh**

The Deviation of Generator i in Zone x ordered by the ISO in BEEP Interval b in Settlement Period t according to Sections 7.2.6.1 or 7.2.6.2, or for settlement according to Section 11.2.4.2.

D 3.7 **$G_{a,bixt}$ – MWh**

The total actual metered Generation of Generator i in Zone x during BEEP Interval b in Settlement Period t.

D 3.8 **$G_{oblig,ixt}$ – MWh**

The total Spinning, Non-Spinning, and Replacement Reserve committed capacity of Generator i in Zone x in Settlement Period t, as reflected in the final Ancillary Services Schedules.

D 3.9 **$G_{a/s,bixt}$ – MWh**

The Energy generated from Ancillary Service resource i in Zone x due to ISO dispatch instructions. This value will be calculated based on the expected Instructed Imbalance Energy during BEEP Interval b in Settlement Period t for which such Ancillary Services dispatch instruction(s) applies.

D 3.9.1 **$G_{s/e,bixt}$ –MWh**

The Energy generated from Supplemental Energy resource i in Zone x due to ISO dispatch instructions. This value will be calculated based on the expected Instructed Imbalance Energy during BEEP Interval b in Settlement Period t for which such Supplemental Energy dispatch instruction(s) applies.

D 3.10 **$GMM_{f,ixt}$ – fraction**

The forecasted Generation Meter Multiplier (GMM) for Generator i in Zone x in Settlement Period t as provided to the Scheduling Coordinator by the ISO in advance of the operation of the Day-Ahead Market.

D 3.11 **$GMM_{f,qxt}$ – fraction**

The forecasted Generation Meter Multiplier for an Energy import at Scheduling Point q in Zone x in Settlement Period t as provided to the Scheduling Coordinator by the ISO in advance of the Day-Ahead Market.

D 3.12 **$GMM_{a,ixt}$ – fraction**

The final forecasted Generation Meter Multiplier (GMM) for a Generator i in Zone x in Settlement Period t as calculated by the ISO at the hour-ahead stage (but after close of the Hour-Ahead Market).

D 3.13 **$GMM_{a,qxt}$ – fraction**

The forecasted Generation Meter Multiplier for an Energy import at Scheduling Point q in Zone x in Settlement Period t as provided to the Scheduling Coordinator by the ISO after close of the Hour-Ahead Market.

D 3.14 **$L_{s,bixt}$ – MWh**

The scheduled Demand of Demand i in Zone x during BEEP Interval b in Settlement Period t as a result of both the Day-Ahead Final Schedule and the Hour-Ahead Final Schedule.

D 3.15 **$L_{a,bixt}$ – MWh**

The actual metered Demand of Demand i in Zone x during BEEP Interval b in Settlement Period t.

D 3.15.1$L_{a,ixt}$ – MWh

The actual metered Demand of Demand i in Zone x in Settlement Period t.

D 3.15.2 **$L_{adj,bixt}$**

The Deviation of Demand i in Zone x ordered by the ISO in BEEP Interval b in Settlement Period t according to Sections 7.2.6.1 or 7.2.6.2, or for settlement according to Section 11.2.4.2.

D 3.16 **$L_{oblig,ixt}$**

The total Non-Spinning and Replacement Reserve comitted capacity of Load i in Zone x in Settlement Period t, as reflected in the final Ancillary Services Schedules.

D 3.17 **$L_{a/s,bixt}$ – MWh**

The Energy reduction by curtailable Load i in Zone x due to ISO dispatch of Ancillary Services from such curtailable Load (i.e., Load bidding into the Ancillary Services markets). This value will be calculated based on the expected Instructed Imbalance Energy during BEEP Interval b in Settlement Period t for which such Ancillary Services dispatch instruction(s) applies.

D 3.17.1 **$L_{s/e,bixt}$ – MWh**

The Energy reduction by curtailable Load i in Zone x due to ISO dispatch of Supplemental Energy from such curtailable Load. This value will be calculated based on the projected impact of the expected Instructed Imbalance Energy during BEEP Interval b in Settlement Period t

D 3.18 **$L_{s,qxt}$ – MWh**

The total scheduled Energy import of Scheduling Coordinator j through Scheduling Point q in Settlement Period t as a result of both the Day-Ahead Final Schedule and the Hour-Ahead Final Schedule.

D 3.19 **$L_{a,bqxt}$ – MWh**

The total actual Energy import of Scheduling Coordinator j through Scheduling Point q in BEEP Interval b during BEEP Interval b in Settlement Period t. This is deemed to be equal to the scheduled Energy over the same interval.

D 3.20 **$I_{adj,bqxt}$ – MWh**

The deviation in real time import of Scheduling Coordinator j through Scheduling Point q in BEEP Interval b during BEEP Interval b in Settlement Period t ordered by the ISO for congestion management, overgeneration, etc. or a result of an import curtailment. This value will be calculated based on the projected impact of the Dispatch instruction(s) (or curtailment event) between the close of the Hour-Ahead Market and the end of the BEEP Interval for which such Dispatch Instructions(s) (or curtailment event) applies.

D 3.21 **$I_{a/s,bqxt}$ – MWh**

The Energy generated from Ancillary Service System Resources of Scheduling Coordinator j through Scheduling Point q in BEEP Interval b during BEEP Interval b in Settlement Period t pursuant to Existing Contracts or Supplemental Energy from interties due to ISO's Dispatch instruction.

D 3.22 **$E_{s,qxt}$ – MWh**

The total scheduled Energy export of Scheduling Coordinator j through Scheduling Point q in Settlement Period t as a result of both the Day-Ahead Final Schedule and the Hour-Ahead Final Schedule.

D 3.23 **$E_{a,bqxt}$ – MWh**

The total actual Energy export of Scheduling Coordinator j through Scheduling Point q in BEEP Interval b of Settlement Period t. This is deemed to be equal to the total scheduled Energy export during the same interval.

D 3.24 **$E_{adj,bqxt}$ – MWh**

The deviation in Real Time export of Scheduling Coordinator j through Scheduling Point q in BEEP Interval b during BEEP Interval b in Settlement Period t ordered by the ISO for Congestion Management, Overgeneration, etc. or as a result of an export curtailment. This value will be calculated based on the projected impact of the Dispatch Instruction(s) (or curtailment event) between the close of the Hour-Ahead Market and the end of the BEEP Interval for which such Dispatch Instruction (or curtailment event) applies.

D 3.25 **P_{bxt} – $/MWh**

The Ex Post Price for Imbalance Energy in Zone x during BEEP Interval b in Settlement Period t.

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 7.4.2), 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 **TL_{bkt} – MWh**

The Transmission Losses per BEEP Interval b of Settlement Period t in utility Service Area k.

D 3.38 **$IGDC_{bixt}$ – $**

The Instructed Imbalance Energy payments/charges for Generator i in Zone x during BEEP Interval b in Settlement Period t.

D 3.39 **$ILDC_{bixt}$ – $**

The Instructed Imbalance Energy payments/charges for Load i in Zone x during BEEP Interval b in Settlement Period t.

D 3.40 **$IIDC_{bqxt}$ – $**

The Instructed Imbalance Energy payments/charges for import at Scheduling Point q during BEEP Interval b in Settlement Period t.

D 3.41 **[Not Used]**

D 3.42 **[Not Used]**

D 3.43 **[Not Used]**

D 3.44 **[Not Used]**

D 3.45 **HBI – Number**

The number of BEEP Intervals in Settlement Period t, currently set to 6.

D 3.46 **[Not Used]**

D 3.47 **[Not Used]**

D 3.48 **$P_{max,ixt}$ – MW**

The maximum capability at which Energy and Ancillary Services may be scheduled from the Generating Unit or System Resource i.

D 3.49 **[Not Used]**

APPENDIX 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 7.2.5 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 Appendix 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 it proportionate share, based on Schedules in the Day-Ahead Market in the direction of Congestion, of the difference between μ_{yth}(L_{yth} - L_{ytd}) 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 $NetZoneImp_{jtxd}$ (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 $NetZoneImp_{jtxh}$ (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 **K_{ytn} (%)**

The percentage of the Inter-Zonal Congestion revenue alocation 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 **L_{ytd} (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 **L_{yth} (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.

APPENDIX 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 7.1.4 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 7.1.4 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 7.1.4 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 7.1.4.3 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 7.1.4 of the ISO Tariff and Section 5 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 2.4.4 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 **$QChargeW_{jqt}$** **(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.

APPENDIX 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:

$$VSST_{xijt} = Max\ \{0, P_{xt} - Sup_{xdecit}\} * DEC_{xit}$$

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.

APPENDIX H

[NOT USED]

APPENDIX 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: Date: Customer Number:	181 20-JUN-97 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	**[Sample charge]**
Invoice Total		______________

SETTLEMENT AND BILLING PROTOCOL

ANNEX 1

ANNEX 1

SETTLEMENT AND BILLING OF

RELIABILITY MUST-RUN CHARGES AND PAYMENTS

1 Objectives, Definitions and Scope

1.1 Objectives

The objective of this Annex 1 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 5.2.8 of the ISO Tariff, of the manner in which the RMR Charges referred to in Section 5.2.7 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 Annex 1. A reference to a paragraph is to a paragraph of this Annex. References to SABP are to the Settlement and Billing Protocol or to the stated paragraph of that Protocol. References to Appendices are to Appendices of SABP.

1.2.2 Definitions of SABP

Unless otherwise specified, any word or expression defined in SABP shall have the same meaning where used in this Annex.

1.2.3 Special Definitions for this Annex

In this Annex 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 Annex 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 Annex 1.

“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 Annex pursuant to Section 5.2.7.3 of the ISO Tariff.

1.2.4 Rules of Interpretation and Other Terms and Conventions

The rules of interpretation set out in SABP 1.2.3, and the provisions of SABP 1.2.4, 1.2.5 and 1.2.6 shall apply to this Annex.

1.3 Scope of Application to Parties

This Annex 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 Annex shall not apply to charges for Energy or Ancillary Services which are payable by the ISO under Sections 2.5 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 SABP. 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 Annex with SABP

Appendices B, G and H of SABP shall apply as appropriate to this Annex. Unless otherwise specified, other provisions of SABP shall not apply to this Annex.

1.5 Relationship of this Annex 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 Annex.

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 Annex 1, Section 5.2.7 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 Annex 1, Section 5.2.7 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 Annex. 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 Annex 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 2.5 and 11 of the ISO Tariff and SABP to the Scheduling Coordinators representing the RMR Owners will be contained in the RMR Payments Calendar pursuant to SABP 2.3.

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 form 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 Annex 1, 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 5.27 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 Annex 1, 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 5.2.7.1 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 5.2.7 of the ISO Tariff, the applicable provisions of the RMR Contract and Section 5.2.7.1 of the ISO Tariff shall apply.

6.4.7 Payment Pending Dispute

Subject to Section 5.2.7.1 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 Annex 1. 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 5.2.7.1.1 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 5.2.7 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 5.2.7 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 SABP.

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 Annex.

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 Annex against amounts owed to that Responsible Utility except as provided by Sections 2.5.27.7 and 5.2.7 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 5.2.7 and 2.5.28 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 Annex 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 SABP 7.1.1, 7.1.2 and 7.1.3 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 Annex, 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 Annex.

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 Annex 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 SABP 9, 10 and 11 shall apply to this Annex 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 5.2.7 of the ISO Tariff or this Annex 1 ("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 Annex

If the ISO determines a need for an amendment to this Annex 1, the ISO shall follow the requirements as set forth in Section 16 of the ISO Tariff, provided that ISO may not modify Annex 1 as it applies to any RMR contract without the consent of the relevant RMR Owner and Responsible Utility.

METERING PROTOCOL

METERING PROTOCOL

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ISO METERING PROTOCOL (MP)

MP 1 OBJECTIVES, DEFINITIONS AND SCOPE

MP 1.1 Objective

The objective of this Metering Protocol is to implement ISO Tariff Section 10 in relation to the acquisition by the ISO of revenue quality meter data for Settlement and billing purposes.

MP 1.1.1 Applicable Reference Materials

This Protocol must be read and interpreted in accordance with:

(a) Section 10 and Appendix J of the ISO Tariff;

(b) Settlement and Billing Protocol (SABP);

(c) American National Standards Institute (ANSI) C12 standards; and

(d) ISO Metered Entity Meter Service Agreements and SC Meter Service Agreements.

MP 1.1.2 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.

MP 1.2 Definitions

MP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is to a Section or an Appendix of the ISO Tariff. References to MP are to this Protocol or to the stated paragraph of this Protocol.

MP 1.2.2 Special Definitions for this Protocol

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

"Authorized Users" means 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.

“Certificate of Compliance” means 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 and this Protocol.

“Check Meter” means 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 and this Protocol.

“Compatible Meter Data Server” means 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 in accordance with this Protocol by the ISO or its authorized representative.

“ISO Metered Entity Meter Service Agreements” means the meter service agreements between the ISO and ISO Metered Entities.

“Line Loss Correction Factor” means the line loss correction factor as set forth in the Technical Specifications.

"MDAS" means the ISO's revenue meter data acquisition and processing system.

"Meter Data Exchange Format" means 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" means 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.

"Metering Facilities" means revenue quality meters, instrument transformers, secondary circuitry, secondary devices, meter data servers, related communication facilities and other related local equipment.

"MP Appendix" means an appendix to this Protocol.

"Proposal for Installation" means a written proposal submitted by an ISO Metered Entity to the ISO describing a proposal for the installation of additional Metering Facilities.

"SC" means Scheduling Coordinator.

"SC Meter Service Agreements" means the meter service agreements between the ISO and SCs.

"Technical Specifications" means Appendices B to G (inclusive) of this Protocol.

"Transformer Loss Correction Factor" means 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.

MP 1.2.3 Rules of Interpretation

The following rules of interpretation and conventions have been adopted in this Protocol:

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol 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 Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the ISO Operations Date.

(e) Any reference to a 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.

MP 1.3 Scope

MP 1.3.1 Scope of Application to Parties

This Protocol applies to the following entities:

(a) the ISO;

(b) ISO Metered Entities; and

(c) SCs in respect of the SC Metered Entities they represent.

If an ISO Metered Entity is also a SC, it shall be treated as an ISO Metered Entity for the purposes of this Protocol and Section 10 of the ISO Tariff. Such an ISO Metered Entity will not be required to enter into a SC Meter Service Agreement unless it represents any metered entities other than itself. A SC Meter Service Agreement entered into by an ISO Metered Entity shall only apply to those metered entities that the ISO Metered Entity represents; the SC Meter Service Agreement shall not apply to the ISO Metered Entity other than in its capacity as SC for those metered entities. If a SC Metered Entity is also a SC, it shall be treated as a SC for the purposes of this Protocol and Section 10 of the ISO Tariff and any references to entities that such a SC represents shall be deemed to include that SC itself.

MP 1.3.2 Scope of SC Responsibilities

SCs will be responsible:

(a) for ensuring that those SC Metered Entities that they represent and which are subject to the procedures and standards set forth in the ISO Tariff and this Protocol, comply with those procedures and standards; and

(b) for providing the ISO with Settlement Quality Meter Data in accordance with the ISO Tariff and this Protocol for those SC Metered Entities that they represent.

MP 1.3.3 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.

MP 2 REVENUE METER DATA ACQUISITION AND PROCESSING SYSTEM (MDAS)

MP 2.1 Purpose of MDAS

MDAS will be used:

(a) by the ISO to obtain and receive the revenue quality meter data of ISO Metered Entities and SC Metered Entities for Settlement and billing purposes; and

(b) by SCs to access Settlement Quality Meter Data held by the ISO in respect of the SC Metered Entities and ISO Metered Entities that they represent.

MP 2.2 ISO Metered Entities

MP 2.2.1 Method of Providing Meter Data to ISO

Subject to any exemption granted by the ISO under MP 13, each ISO Metered Entity must provide Meter Data to MDAS by direct interface between MDAS and its revenue quality meter or Compatible Meter Data Server.

MP 2.2.2 Interface with MDAS

ISO Metered Entities will, in accordance with the ISO Tariff and this Protocol, use WEnet to interface directly with MDAS:

(a) in the case of Meter Data provided to MDAS from a revenue quality meter, via compatible metering communication equipment; or

(b) via a Compatible Meter Data Server.

MP 2.2.3 Frequency of Recording and Collecting Data

Subject to any exemption granted by the ISO under MP 13, 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 MP 13, within the time period specified in that exemption.

MP 2.2.4 Format for Data Submission

MP 2.2.4.1 Data Provided Directly From Meters

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.

MP 2.2.4.2 Data Provided From Meter Data Servers

ISO Metered Entities or SCs 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.

MP 2.2.4.3 Netting

(a) Permitted Netting

ISO Metered Entities may, when providing Meter Data to the ISO pursuant to this MP 2.2, 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.

(b) 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 and this Protocol.

MP 2.2.5 Format for Data Requests

SCs 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 SCs within 5 Business Days of the relevant Trading Day.

MP 2.3 SC Metered Entities

MP 2.3.1 Method of Submitting Meter Data to ISO

SCs must submit Settlement Quality Meter Data for those SC Metered Entities they represent to MDAS when required to submit that data in order to meet the requirements of SABP and the ISO Payments Calendar.

MP 2.3.2 Interface with MDAS

SCs shall utilize a Compatible Meter Data Server to interface with MDAS via WEnet.

MP 2.3.3 Frequency of Submitting Data

SCs shall submit Settlement Quality Meter Data to the ISO when required to do so by the SABP and the ISO Payments Calendar. SCs 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 SC from which the ISO demands that data must submit it to the ISO within 4 hours of receiving the demand from the ISO.

MP 2.3.4 Format for Data Submission

SCs shall submit Settlement Quality Meter Data to MDAS for the SC Metered Entities they represent using the Meter Data Exchange Format. Subject to any exemption granted by the ISO under MP 13, SCs 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 SC Metered Entities.

Each SC shall submit Settlement Quality Meter Data for all of the SC 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 SCs may be in either kWh or MWh values.

MP 2.3.5 Netting

(a) Permitted Netting

SCs may, when providing Settlement Quality Meter Data to the ISO pursuant to this MP 2.3, net values for Generating Unit output and auxiliary load equipment electrically connected to that Generating Unit at the same point.

(b) Prohibited Netting

SCs may not net values for Generating Unit output and Load. SCs representing SC Metered Entities that serve third-party Load connected to the auxiliary system of a Generating Unit must ensure that those SC Metered Entities add the Energy consumed by such third-party Load to that Generating Unit's output so as to ensure proper Settlement of that Generating Unit's gross output.

MP 2.3.6 Format for Data Requests

SCs may obtain Settlement Quality Meter Data relating to the SC 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.

MP 2.4 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 SC with access to Meter Data or Settlement Quality Meter Data provided that the SC requesting access represented the entity that submitted that data at the time the data was submitted to the ISO.

MP 3 CERTIFICATION OF METERING FACILITIES

MP 3.1 ISO Metered Entities

MP 3.1.1 Requirement to Certify

Subject to any exemption granted by the ISO under MP 13, the ISO will not accept Meter Data from an ISO Metered Entity unless that Meter Data is produced by Metering Facilities that are certified in accordance with this Protocol and the ISO Tariff and have a current Certificate of Compliance.

MP 3.1.2 Responsibility for Obtaining Certification

An ISO Metered Entity that is required to make Meter Data available to the ISO under this Protocol or the ISO Tariff is responsible for having the Metering Facilities that it will use to produce that Meter Data certified by the ISO or an ISO Authorized Inspector in accordance with the ISO Tariff and this Protocol.

MP 3.1.3 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.

MP 3.1.4 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.

MP 3.1.5 Criteria for Certification

Subject to any exemption granted by the ISO under MP 13, the criteria for certifying the Metering Facilities of ISO Metered Entities pursuant to the ISO Tariff and this Protocol are the criteria set forth in the Technical Specifications.

MP 3.1.6 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.

MP 3.1.7 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 and this Protocol.

MP 3.1.8 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 or this Protocol; 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 this MP 3.1. Such request must indicate that it relates to Metering Facilities in respect of which the ISO has previously revoked a Certificate of Compliance.

MP 3.1.9 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 or this Protocol. The ISO may, at its discretion, require those Metering Facilities to be recertified.

MP 3.2 ISO Authorized Inspectors

MP 3.2.1 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.

MP 3.2.2 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.

MP 3.3 SC Metered Entities

MP 3.3.1 Requirement to Certify

Subject to any exemption granted by the ISO under MP 13, the ISO will not accept Settlement Quality Meter Data relating to a SC Metered Entity unless it is produced by Metering Facilities that are certified in accordance with:

(a) the certification or similar criteria prescribed by the relevant Local Regulatory Authority; or

(b) if that Local Regulatory Authority has not prescribed any certification or similar criteria for Metering Facilities, the certification criteria prescribed by this Protocol and those Metering Facilities have a current Certificate of Compliance.

MP 3.3.2 SC to Ensure Certification

If the relevant Local Regulatory Authority has not prescribed any certification criteria for the Metering Facilities of a SC Metered Entity, the SC representing that SC Metered Entity must promptly notify the ISO in writing that no such criteria have been prescribed. That SC will then be responsible for ensuring that the SC Metered Entities it represents obtain and maintain Certificates of Compliance in respect of all of the Metering Facilities of those SC Metered Entities in accordance with MP 3.1. SCs must engage an ISO Authorized Inspector to perform the certification of any Metering Facilities that are to be certified under this Protocol or the ISO Tariff.

MP 3.3.3 Certification of Meter Data Servers

Subject to any exemption granted by the ISO under MP 13, the ISO will not accept Settlement Quality Meter Data relating to a SC Metered Entity from a meter data server unless that meter data server is a Compatible Meter Data Server.

MP 3.3.4 Confirmation of Certification

On the written request of the ISO, each SC must give the ISO written confirmation that the Metering Facilities of each SC 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 Protocol within 5 Business Days of receiving a request from the ISO.

MP 3.3.5 ISO's Request for Certificates

The ISO may require SCs to provide it with a copy of any certificate issued by a Local Regulatory Authority in respect of the Metering Facilities of each SC Metered Entity they represent. The SC must provide to the ISO a copy of such certificate within 5 Business Days of receiving the request for the certificate from the ISO.

MP 3.3.6 Deemed Certification

In accordance with Section 10.6.6.2 of the ISO Tariff, those revenue quality meters of SC Metered Entities that are subject to certification pursuant to this Protocol and 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 and this Protocol. 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 and this Protocol.

MP 4 AUDITING AND TESTING OF METERING FACILITIES

MP 4.1 ISO Metered Entities

MP 4.1.1 Requirement for Audits and Tests

Subject to any exemption granted by the ISO under MP 13, the Metering Facilities of ISO Metered Entities are subject to audit and testing by the ISO, or its authorized representative, in accordance with Section 10.5.1 of the ISO Tariff and this Protocol. 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.

MP 4.1.2 Failure to Comply

The rights, powers, authorities and measures available to the ISO in respect of any failure by an ISO Metered Entity to comply with the ISO's audit or test procedures will be set forth in the ISO Metered Entity Meter Service Agreements.

MP 4.2 SC Metered Entities

MP 4.2.1 Requirement for Audit and Testing

(a) Audit and Testing by SC

Each SC shall at least annually conduct (or engage an independent, qualified entity to conduct) audits and tests of the Metering Facilities of the SC Metered Entities that it represents and the Meter Data provided to the SC in order to ensure compliance with all applicable requirements of any relevant Local Regulatory Authority. SCs 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 SCs and SC Metered Entities are subject to audit and testing by the ISO or an ISO Authorized Inspector in accordance with Section

10.6.7.7 of the ISO Tariff and this Protocol. 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 SC, SC Metered Entity or an ISO Authorized Inspector engaged by the SC, SC Metered Entity or the ISO to carry out those audits or tests.

MP 4.2.2 Failure to Comply

The rights and measures available to the ISO with respect to any failure by a SC or a SC Metered Entity to comply with any applicable audit or test procedures contained in the ISO Tariff and this Protocol, will be set forth in the SC Meter Service Agreements.

MP 5 INSTALLATION OF ADDITIONAL METERING FACILITIES

MP 5.1 ISO Requirement to Install Additional Metering

MP 5.1.1 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.

MP 5.1.2 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.

MP 5.1.3 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 MP 5.1.2.

MP 5.1.4 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.

MP 5.1.5 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.

MP 5.1.6 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 pursuant to MP 5.1.6(c), 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.

MP 5.1.7 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 MP 5.1.2, 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.

MP 5.2 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.

MP 6 MAINTENANCE OF METERING FACILITIES

MP 6.1 ISO Metered Entities

MP 6.1.1 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) and this Protocol.

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 and this Protocol, 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 MP 10.1. That estimated meter data will be used by the ISO in its Settlement and billing process.

MP 6.1.2 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 and this Protocol, 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 MP 10.1. 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.

MP 6.2 SC Metered Entities

SCs will be required to ensure that the SC Metered Entities that they represent maintain their Metering Facilities in accordance with the requirements of the relevant Local Regulatory Authority. If a SC Metered Entity's Local Regulatory Authority has not set any requirements in relation to the maintenance of its Metering Facilities, the SC representing that SC Metered Entity must ensure that it maintains its Metering Facilities in a manner that ensures that those Metering Facilities continue to meet the standards set forth in the ISO Tariff (including Appendix J) and this Protocol.

MP 7 STANDARDS FOR METERING FACILITIES

MP 7.1 ISO Metered Entities

MP 7.1.1 Obligation to Meet Standards

ISO Metered Entities must ensure that their Metering Facilities comply with the standard and accuracy requirements referred to in Section 10.2.3 of the ISO Tariff and this Protocol. 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 and this Protocol.

MP 7.1.2 Applicable Standards

ISO Metered Entities must ensure that their Metering Facilities comply with the standards for Metering Facilities referred to in:

(a) Appendix J to the ISO Tariff; and

(b) the Technical Specifications.

MP 7.1.3 Failure to Comply with Standards

The rights, powers, authorities and measures available to the ISO with respect to any failure by ISO Metered Entities to comply with the standards for Metering Facilities referred to in the ISO Tariff and this Protocol, will be set forth in the ISO Metered Entity Meter Service Agreements.

MP 7.2 SC Metered Entities

SCs will be required to ensure that the SC Metered Entities that they represent comply with the standards for Metering Facilities of the relevant Local Regulatory Authority. If a SC Metered Entity's Local Regulatory Authority has not set any requirements in relation to standards for Metering Facilities, the SC representing that SC Metered Entity must ensure that it complies with the standards for Metering Facilities referred to in the ISO Tariff (including Appendix J) and this Protocol.

MP 8 LOW VOLTAGE SIDE METERING

MP 8.1 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 10.4 of the ISO Tariff and this Protocol. 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 MP 8.4.

MP 8.2 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.

MP 8.3 ISO's Grounds for Approval

The ISO shall approve a request made under MP 8.2 only if the ISO is satisfied that adequate accuracy and security of Meter Data obtained can be assured in accordance with Section 10.4 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.

MP 8.4 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.

MP 9 SECURITY OF METER DATA

MP 9.1 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.

MP 9.1.1 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.

MP 9.1.2 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.

MP 9.1.3 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.

MP 9.2 SC Metered Entities

SCs must use Compatible Meter Data Servers to submit Settlement Quality Meter Data to the ISO for those SC Metered Entities that they represent. SCs 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 SCs so as to ensure the security of those servers. Each SC must also provide the ISO with the WEnet protocol address of the SC’s file server with which MDAS will interface to obtain or provide Settlement Quality Meter Data.

MP 9.3 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.

MP 10 VALIDATION, EDITING AND ESTIMATING OF METER DATA

MP 10.1 ISO Metered Entities

Subject to any exemption granted by the ISO under MP 13, 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.

MP 10.1.1 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.

MP 10.2 SC Metered Entities

SCs are responsible for providing the ISO with Settlement Quality Meter Data for the SC Metered Entities they represent and for ensuring that any validation, editing and estimation requirements of any relevant Local Regulatory Authority or the ISO (where the SC Metered Entity is subject to the ISO requirements for validation, editing and estimation) have been properly implemented. The ISO will not perform any validation, editing or estimating on the Settlement Quality Meter Data it receives from SCs.

MP 11 COMMUNICATIONS

MP 11.1 Facilities Provided by the ISO

The ISO will provide the facilities referred to in this MP 11.1 to acquire Meter Data from ISO Metered Entities and receive Settlement Quality Meter Data from SCs.

MP 11.1.1 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.

MP 11.1.2 WEnet

MDAS will use WEnet to acquire Meter Data from ISO Metered Entities and receive Settlement Quality Metered Data from SCs. WEnet is an ISO-provided Wide Area Network (WAN). WEnet will use the TCP/IP networking protocol.

MP 11.1.3 Points of Presence (POP)

WEnet will have a Point of Presence (POP) in the general vicinity of most ISO Metered Entities and SCs. The POP is the interface point between WEnet and the facilities provided by ISO Metered Entities and SCs pursuant to MP 11.2 and MP 11.3.

MP 11.1.4 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 SCs.

MP 11.2 Facilities Provided by ISO Metered Entities

ISO Metered Entities must provide the telecommunication facilities referred to in MP 11.2.1 to MP 11.2.3 inclusive to connect their Compatible Meter Data Servers to the WEnet POP.

MP 11.2.1 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.

MP 11.2.2 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.

MP 11.2.3 Meter Data Server

ISO Metered Entities must use a Compatible Meter Data Server to interface with MDAS.

MP 11.3 Facilities provided by SCs

SCs must use a Compatible Meter Data Server to interface with MDAS.

MP 12 METER IDENTIFICATION

MP 12.1 SC Metered Entities

If a SC Metered Entity is required to identify its revenue quality meters by the relevant:

(a) Local Regulatory Authority; or

(b) UDC,

then the SC representing that SC 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 SC Metered Entity is not required by either the relevant Local Regulatory Authority or UDC to identify its revenue quality meters, the SC representing that SC Metered Entity shall maintain an accurate record of the revenue quality meter of each of the SC Metered Entities that it represents from time to time. The record maintained by SCs must include the information set out in the Technical Specifications. The SC 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.

MP 13 EXEMPTIONS FROM COMPLIANCE

MP 13.1 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 and this Protocol.

MP 13.2 Guidelines for Granting Exemptions

The ISO will use the following guidelines when considering applications for exemptions from compliance with the ISO Tariff and this Protocol.

(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.

MP 13.3 Procedure for Applying for Exemptions

All applications to the ISO for exemptions from compliance with the requirements of the ISO Tariff or this Protocol 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.

MP 13.4 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 and/or this Protocol 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.

MP 13.5 Permitted Exemptions

MP 13.5.1 Exemptions from Providing Meter Data Directly to MDAS

(a) General

The ISO has the authority under Section 10.2.5 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 MP 13.5.1(b), 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 this Protocol and 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 SC Metered Entities for the purposes of this Protocol and the ISO Tariff.

iii. SCs inability to directly poll MDAS

If a SC 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 SC 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 SC is unable to directly poll MDAS, that SC will be responsible for providing the ISO with Settlement Quality Meter Data for its ISO Metered Entities in accordance with this Protocol and 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 Server in accordance with this Protocol.

MP 13.5.2 Exemptions from Meter Standards

(a) General

The ISO has the authority under Section 10.5.2 of the ISO Tariff to exempt ISO Metered Entities from the requirement to comply with the meter standards referred to in the ISO Tariff and this Protocol.

(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 and this Protocol 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 and this Protocol. 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 in this Protocol 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

SCs may request the ISO to grant an exemption from the requirement to provide Settlement Quality Meter Data to the ISO for SC 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 this Protocol and the ISO Tariff. The SC representing such Generators will be required to apply the relevant distribution loss factors to that Generator's Meter Data (the SC 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 and this Protocol, 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.

MP 13.5.3 Exemptions from Audit, Testing or Certification

The ISO has the authority under Section 10.5.2 of the ISO Tariff to exempt ISO Metered Entities from the metering standards referred to in the ISO Tariff and this Protocol.

MP 14 AMENDMENTS TO THE PROTOCOL

If the ISO determines a need for an amendment to this Protocol, the ISO will follow the requirements as set forth in Section 16 of the ISO Tariff.

METERING PROTOCOL

APPENDICES A-G

APPENDIX 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 SCs 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 SCs using voice communications; and

(b) inform ISO Metered Entities and SCs 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 SCs via the WEnet.

APPENDIX B

CERTIFICATION PROCESS FOR METERING FACILITIES

Paragraphs B1 to B3 of this Appendix 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 SC Metered Entities where no certification requirements are imposed on a SC Metered Entity by its Local Regulatory Authority.

Paragraph B5 of this Appendix 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/SC Metered Entity

The ISO Metered Entity or SC 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 SC 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 Appendix) 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 SC 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 SC 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 Protocol, the ISO shall provide written notice of the deficiencies to the ISO Metered Entity or SC 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 MP 13.5.1 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 SC Metered Entity is incomplete or fails to meet the relevant standards referred to in the ISO Tariff and this Protocol; 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 MP 3.1.3, 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 Appendix; 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 ☐ (info. is attached) No ☐			

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**	**B**	**C**	Name Plate	**A**	**B**	**C**
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 ☐ Fail ☐	Pass ☐ Fail ☐	Pass ☐ Fail ☐

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 Appendix.
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.

APPENDIX 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 Appendix D of this Protocol.

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 Protocol 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 Protocol 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).

APPENDIX D

STANDARDS FOR METERING FACILITIES

The standards for Metering Facilities referred to in this Appendix 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 Appendix apply to ISO Metered Entities and, where the relevant Local Regulatory Authority has not set any standards, to SC 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 Appendix, the detailed standards shall prevail.

D 3 Detailed Standards for New Meters

Exhibit 1 to this Appendix 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 Appendix 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 APPENDIX D

SPECIFICATION MTR1-96

ENGINEERING SPECIFICATION
FOR POLYPHASE SOLID-STATE
ELECTRICITY REVENUE QUALITY METERS
FOR USE ON THE ISO CONTROLLED GRID

TABLE OF CONTENTS

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) Kilovar-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 an 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 it's 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) ± 0.2% at full load at power factor of 100%;

(b) ± 0.25% at full load at power factor of 50% lag;

(c) ± 0.25% at full load power factor at 50% lead; and

(d) ± 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. ± 0.2% at Full load at power factor of 100%;

ii. ± 0.25% at Full load at power factor of 50% lag;

iii. ± 0.25% at Full load at power factor of 50% lead; and

iv. ± 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°±2° 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 ±2° 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 APPENDIX 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).

APPENDIX 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 hystersis 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:

$$\text{WATTS Compensation Value} = \frac{\text{Measured Voltage}^2}{\text{Calibration Point Voltage}^2} * \%\text{LWFE} + \frac{\text{Measured Current}^2}{\text{Calibration Point Current}^2} * \%\text{LWCU}$$

$$\text{Vars Compensation Value} = \frac{\text{Measured Voltage}^4}{\text{Calibration Point Voltage}^4} * \%LVFE + \frac{\text{Measured Current}^2}{\text{Calibration Point Current}^2} * \%LVCU$$

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*).

$$Percent\ Use = \frac{Contract\ kW \Big/ \%\ Power\ Factor}{Max. Available\ kVa}$$

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 Appendix. 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 Appendix.

- 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

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 at:	10 A
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:

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

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			

APPENDIX 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 Appendix.

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 *cosQ* 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:

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:

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 watthour 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 Appendix. 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 Appendix.

- 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

CT Test Data:

Phase ‘A’ CT Mfr. & Serial Number:

Ratio Correction Factor (RCF^I)	1.0003	1.0002
Phase Angle (β) (minutes)	-0.3	2.2

Phase ‘B’ CT Mfr. & Serial Number:

Ratio Correction Factor (RCF^I)	1.0004	1.0029
Phase Angle (β) (minutes)	-0.4	2.2

Phase ‘C’ CT Mfr. & Serial Number:

Ratio Correction Factor (RCF^I)	1.0019	1.0028
Phase Angle (β) (minutes)	-0.3	3.1

Average of CT’s Mfr. & Serial Number:

Ratio Correction Factor (RCF^I)	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
Phase Angle (γ) (minutes)	1.5

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
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:

CT Test Data:

Phase 'A' CT Mfr. & Serial Number:

	Full Load	Light Load
Ratio Correction Factor (RCF^I)		
Phase Angle (β) (minutes)		

Phase 'B' CT Mfr. & Serial Number:

	Full Load	Light Load
Ratio Correction Factor (RCF^I)		
Phase Angle (β) (minutes)		

Phase 'C' CT Mfr. & Serial Number:

	Full Load	Light Load
Ratio Correction Factor (RCF^I)		
Phase Angle (β) (minutes)		

Average of CT's Mfr. & Serial Number:

	Full Load	Light Load
Ratio Correction Factor (RCF^I)		
Phase Angle (β) (minutes)		

VT Test Data:

Phase 'A' VT Mfr. & Serial Number:

Ratio Correction Factor (RCF^E)	
Phase Angle (γ) (minutes)	

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			

APPENDIX G

ISO DATA VALIDATION, ESTIMATION AND EDITING PROCEDURES

This Appendix 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 SC 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 Appendix.

(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 Appendix 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

$$\text{Estimated Interval} = \frac{\text{Next Actual - Previous Actual Interval}}{\text{Number of Missing Intervals + 1}} + \text{Previous Actual Interval}$$

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 then 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.

ELIGIBLE INTERMITTENT RESOURCES PROTOCOL

ELIGIBLE INTERMITTENT RESOURCES PROTOCOL

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ELIGIBLE INTERMITTENT RESOURCES PROTOCOL (EIRP)

EIRP 1 Objectives, Definitions and Scope

EIRP 1.1 Objectives

The objectives of this Protocol are to:

(a) Implement those sections of the ISO Tariff which involve Eligible Intermittent Resources and Participating Intermittent Resources;

(b) Describe the requirements for Eligible Intermittent Resources that intend to be certified as Participating intermittent Resources;

(c) Describe the ISO's responsibilities for certification, forecasting and performance monitoring of Participating Intermittent Resources; and

(d) Describe the responsibilities of Participating Intermittent Resources for operating and maintaining facilities, providing information in support of Energy forecasts, and scheduling Energy.

EIRP 1.2 Definitions

EIRP 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 Protocol. A reference to a Section or an Appendix is a reference to a Section or an Appendix of the ISO Tariff. References to EIRP are to this Protocol or to the stated paragraph of this Protocol.

EIRP 1.2.2 Special Definitions for this Protocol

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

"Forecast Fee" means the charge imposed on a Participating Intermittent Resource pursuant to the terms of this Protocol and ISO Tariff Appendix F, Schedule 4.

"Hour-Ahead Forecast" means the Energy forecast to be used by the Scheduling Coordinator representing a Participating Intermittent Resource for its Preferred Hour-Ahead Schedule, in accordance with EIRP 5.

EIRP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol 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 Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of the date posted on the ISO Home Page.

(e) Time references in this Protocol are references to prevailing Pacific time.

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 2.3 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 Intermitted 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 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 and other information the ISO reasonably requests to fulfill its obligation to validate forecast models and explain deviations.

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 as specified in SP 3.3.1.

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 20.3 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 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 16 of the ISO Tariff.

DYNAMIC SCHEDULING PROTOCOL

ANCILLARY SERVICES REQUIREMENTS Protocol

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DYNAMIC SCHEDULING PROTOCOL (DSP)

DSP 1 OBJECTIVES, DEFINITIONS, AND SCOPE

DSP 1.1 Objectives

The objectives of this Protocol are to implement the ISO Tariff provisions relating to dynamic imports of Energy, Supplemental Energy, and Energy associated with non-Regulation Ancillary Services (Spinning Reserve and Non-Spinning Reserve) by Scheduling Coordinators from System Resources.

DSP 1.2 Definitions

DSP 1.2.1 Master Definitions Supplement

Any word or expression defined in the Master Definitions Supplement to the ISO Tariff shall have the same meaning where used in this Protocol. A reference to a Section or an Appendix is a reference to a Section or an Appendix of the ISO Tariff. References to DSP are to this Protocol or to the stated paragraph of this Protocol.

DSP 1.2.2 Special Definitions for this Protocol

In this Protocol, the following expressions shall have the meaning set opposite them:

"Host Control Area" means the Control Area in which a System Resource subject to this Protocol is connected to the electric grid. The Host Control Area may, or may not, be directly interconnected with the ISO Control Area.

"Intermediary Control Area" means 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.

DSP 1.2.3 Rules of Interpretation

(a) Unless the context otherwise requires, if the provisions of this Protocol and the ISO Tariff conflict, the ISO Tariff will prevail to the extent of the inconsistency. The provisions of the ISO Tariff have been summarized or repeated in this Protocol only to aid understanding.

(b) A reference in this Protocol 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 Protocol are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Protocol.

(d) This Protocol shall be effective as of June 29, 2004. Any amendment to this Protocol shall be effective as of the date of such amendment, or as of the date such amendment is approved by FERC.

DSP 1.3 Scope

DSP 1.3.1 Scope of Application to Parties

The DSP applies to the following entities:

(a) Scheduling Coordinators (SCs);

(b) System Resources;

(c) Host Control Areas;

(d) Intermediary Control Areas;

(e) the ISO

[Others?]

DSP 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.

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 2.2.7.6 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. (See the form of ICAOA service schedule and alternative special agreement for Host Control Areas attached to these standards.)

DSP 3.2 The SC 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. (See the form of agreement attached to these standards.)

DSP 3.3 The SC 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). Every change in the magnitude of the dynamic schedule by 25% or more, or 25 MW, whichever is less, shall require a conforming change in the associated e-tag.

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 SC 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 SC 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

SCs and Host Control Areas that are already certified under the ISO's Standards for Imports of Regulation will be deemed to have fulfilled the requirements of this Protocol (all presently implemented Regulation import functionalities may be subject to review to ensure consistency between such functionalities and the requirements of this Protocol). SCs 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 SC 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 to these standards).

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 SC 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 intertie (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 SCs 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 APPENDIX 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, and the ISO's *"Standards for Dynamic Imports of Energy, Supplemental Energy, and Energy Associated with Non-Regulation Ancillary Services"* posted on the ISO's internet web site (www.caiso.com), as may be modified from time to time ("Standards"), ______________________________, as Scheduling Coordinator, and _______________________________, as Host Control Area operator (as such term is referred to in the Standards, 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 Standards. 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, applicable agreements, and the Standards 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 Standards.

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:

(a) ______________________________________, 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: ________________________________