California ISO
Your Link to Power

California Independent
System Operator Corporation

December 30, 2010

VIA ELECTRONIC FILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, D.C. 20246

Re: California Independent System Operator Corporation
Docket No. ER11- ___________

Tariff Clarifications Amendment

Dear Secretary Bose:

The California Independent System Operator Corporation (ISO)[1] requests approval of a number of clarifying revisions to its tariff.[2] The purpose of these amendments is to clarify the meaning of existing tariff provisions, ensure consistency throughout the tariff as well as between the tariff and business practices, and correct typographical and other inadvertent errors. The ISO requests an effective date for these tariff changes of February 28, 2011.

I. Background

In advance of the implementation of its new markets in 2009, the ISO undertook a review of its tariff to assess the need for additional implementation details in its tariff and to correct inadvertent errors. This review process resulted in tariff revisions that

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1 The ISO is sometimes referred to CAISO. Capitalized terms not otherwise defined herein have the meanings set forth in the Master Definitions Supplement, Appendix A to the currently effective ISO tariff. References in this filing to section numbers are references to sections of the ISO tariff, and references to appendices are references to appendices of the ISO tariff, unless the context indicates otherwise.

2 The ISO submits this filing pursuant to Section 205 of the Federal Power Act, 16 U.S.C. § 824d, Part 35 of the Commission's regulations, 18 C.F.R. Part 35, and in compliance with Order No. 714, *Electronic Tariff Filings*, FERC Stats. & Regs. ¶ 31,276 (2009).

were filed with and approved by the Commission.[3] Over the course of 2010, the ISO has undertaken a similar tariff review to clarify existing tariff language and correct inadvertent errors and inconsistencies in its tariff. This effort does not alter established policies or change the rights and obligations of the ISO or its market participants. Instead, this effort is intended to clarify the meaning of existing tariff provisions, ensure consistency throughout the tariff as well as between the tariff and applicable business practices, and correct typographical and other inadvertent errors. The ISO has discussed its proposed tariff changes with stakeholders and has incorporated a number of stakeholder proposals into this filing.[4] The ISO intends to undertake a similar review of its tariff on at least an annual basis in future years and will propose amendments to its tariff as appropriate.

II. Proposed Tariff Modifications

The ISO has included a key to its proposed tariff amendments as Attachment A hereto. This document identifies each tariff section the ISO is proposing to change as well as the reason for the changes proposed to the section. Many of these amendments are self-explanatory. For example, in section 4.3.1.2, the ISO is proposing to add a comma to improve the grammar of the first sentence of that section. In section 4.5.1.3, the ISO is proposing to replace references to "Scheduling Coordinator Identification Code" with "Scheduling Coordinator ID Code" to conform the language in this section to the defined term as it appears in the ISO tariff, Appendix A, Master Definitions Supplement. In section 4.5.3.2.2, the ISO is proposing to capitalize the word "schedules" in order to conform the term Interchange Schedules in this section as it appears in the ISO tariff, Appendix A, Master Definitions Supplement. As part of proposed changes to section 8.9.15.2, the ISO has provided cross-references to tariff sections that specify financial penalties resulting from the failure of a resource providing residual unit commitment capacity or an ancillary service to pass a performance audit. The ISO refers the Commission to Attachment A to this filing for descriptions of these and other changes. In the paragraphs below, the ISO provides additional information on specific tariff clarifications it is proposing to make as part of this filing, in the order that these proposed changes appear in the tariff sheets submitted with this filing as Attachment B and Attachment C.

Section 1.3.2

Section 1.3.2 of the current ISO tariff states that if the provisions of an ISO protocol and sections 1 through 4 of the ISO tariff conflict, the provisions in sections 1 through 4 will prevail to the extent of the inconsistency. The ISO proposes to remove

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[3] *See California Independent System Operator Corp*. 126 FERC ¶ 61,262 (2009); Commission Letter Order, Docket Nos. ER09-556-001, *et al.* (Oct. 19, 2009); Commission Letter Order, Docket Nos. ER06-615-054, *et al.* (Jan. 19, 2010).

[4] This stakeholder process is discussed further in Section III of this transmittal letter.

the references to sections 1 through 4, which are outdated, and clarifies that if the provisions of an ISO protocol and the tariff conflict, the tariff will prevail to the extent of the inconsistency.

Sections 4.5.3.7, 19, and 31.6.4

The ISO proposes to delete the text of section 4.5.3.7 which addresses the responsibilities of scheduling coordinators to submit forecasted monthly and annual peak demand in the ISO balancing authority area or annual generation capacity as applicable. The resource adequacy provisions set forth in section 40 of the ISO tariff have superseded the requirement of section 4.5.3.7. These provisions require scheduling coordinators representing load serving entities to submit monthly and annual demand forecasts. The provisions also require scheduling coordinators representing resource adequacy resources to submit monthly and annual supply plans. The ISO is also proposing to delete the provisions of section 19 pertaining to scheduling coordinator and load serving entity demand forecast responsibilities and the provisions of section 31.6.4 concerning the submission of demand information from scheduling coordinators for the same reason.

Section 4.6

In section 4.6 of the tariff, the ISO proposes to modify language to clarify the circumstances under which a generator with a generating unit in the ISO balancing authority area must enter into an agreement with the ISO to establish the terms associated with its obligation to submit bids, including self-schedules, in the ISO market. The proposed changes specify that the ISO will only accept bids through scheduling coordinators from generators with generating units interconnected to the electric grid within the ISO balancing authority area and that have entered into a participating generator agreement or a qualifying facility participating generator agreement. This clarification also adds a reference to metered subsystem agreements to these existing requirements, which reflects the ISO's existing practices in applying this tariff provision.

Section 4.6.3.1 and Appendix A

In section 4.6.3.1, the ISO proposes to clarify that a generating unit with a rated capacity less than 500 kW is not eligible to participate in the ISO's markets, unless the generating unit is participating in an aggregation agreement approved by the ISO. These revisions clarify the circumstances under which a generator with a small generating unit may be exempt from compliance with ISO tariff requirements applicable to participating generators. This clarification is a companion to the ISO's proposed revisions to the definition of *Participating Generator* in Appendix A of the ISO tariff, and both sets of revisions conform to similar tariff amendments filed by the ISO and conditionally accepted by the Commission in Docket No. ER10-1755.[5]

Section 4.6.5.1

In section 4.6.5.1, the ISO proposes to clarify that participating generators shall, in relation to each of their generating units, meet all *Applicable Reliability Criteria*. The ISO tariff defines *Applicable Reliability Criteria* to mean: "The reliability standards established by NERC, WECC, and Local Reliability Criteria as amended from time to time, including any requirements of the NRC."[6] The ISO's proposed amendment is consistent with the mandatory reliability standards approved by the Commission under its authority pursuant to section 215 of the Federal Power Act[7] and clarifies the existing tariff requirement of section 4.6.5 that participating generators meet all applicable WECC standards.

Sections 4.6.5.2 and 4.6.5.3, and Appendices A, V, and BB

With respect to sections 4.6.5.2 and 4.6.5.3, the ISO proposes to delete these provisions of ISO tariff as well as the associated defined term *WSCC Reliability Criteria Agreement* that appears in the ISO tariff, Appendix A, and is used solely to implement those sections. These provisions of the ISO tariff require participating generators to enter into a reliability management system agreement with WECC. The ISO incorporated this requirement into the tariff solely for the purpose of satisfying the requirements of its own reliability management system agreement with WECC. On October 11, 2010, WECC filed with the Commission, in Docket No. ER11-91-000, a notice of proposed cancellation of its reliability management system agreement originally filed in Docket No. ER99-3396-000, wherein WECC represented that the reliability management system served as a predecessor to the mandatory reliability standards developed and enforced by NERC and WECC and that the Commission's approval of these standards rendered the reliability management system redundant and obsolete. Effective November 16, 2010, subject to any necessary Commission approval, the ISO and WECC executed an agreement to terminate the reliability management system agreement and, with respect to the ISO, the reliability criteria agreement. On December 6, 2010, the Commission issued a letter order accepting WECC's cancellation filing in Docket No. ER11-91-000.

The ISO sees no further purpose in requiring generators to comply with the WECC requirements for generators set forth in sections 4.6.5.2 and 4.6.5.3 and requests authority to amend them as requested. The ISO also proposes conforming

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[5] *See California Independent System Operator Corp*. 132 FERC ¶ 61,211 (2010).

[6] ISO tariff, Appendix A, Master Definitions Supplement.

[7] 16 U.S.C. §824o.

changes to its *pro forma* Large Generator Interconnection Agreements set forth in Appendix G, Appendix V, and Appendix BB of the ISO tariff.

<u>Section 4.10.1.5.1</u>

In section 4.10.1.5.1, the ISO proposes to clarify that a candidate congestion revenue rights holder must identify its affiliates as part of the application process. This clarification aligns section 4.10.1.5.1 with section 39.9 of the ISO tariff, which describes monitoring and affiliate disclosure requirements for congestion revenue rights holders. Section 39.9 currently provides in relevant part as follows: "Each CRR Holder or Candidate CRR Holder must notify the CAISO of any Affiliate that is a CRR Holder, Candidate CRR Holder, or Market Participant, any Affiliate that participates in an organized electricity market in North America, and any guarantor of any such Affiliate." The Commission should therefore authorize the ISO's proposed change to section 4.10.1.5.1.

<u>Sections 6.5.1.1.1 and 6.5.1.1.2, *et al*.</u>

Sections 6.5.1.1.1 and 6.5.1.1.2 identify information that the ISO discloses on an annual and monthly basis to market participants with non-disclosure agreements. These sections include the use of the term *Constraints*, which is defined in Appendix A of the ISO tariff as "[p]hysical and operational limitations on the transfer of electrical power through transmission facilities." The ISO proposes to replace the defined term *Constraints* in sections 6.5.1.1.1 and 6.5.1.1.2 with the new defined term *Transmission Constraints*, which will have the same meaning. The proposed change will have no impact on the information that the ISO discloses pursuant to these tariff sections. The ISO also proposes to make similar changes to a number of other tariff sections that use the term *Constraint* or a variation of that term such as *network Constraint* or *transmission Constraint*.[8]

In addition, a number of other tariff sections inadvertently use the defined term *Constraint*, which related to transmission facilities, but instead should use the word *constraint* in a more generic sense. This has created some confusion, which the ISO proposes to eliminate by modifying the relevant tariff sections to refer to constraint in lower-case text, in order to reflect the plain English meaning of the word rather than its tariff-defined meaning.[9]

These proposed changes do not alter the substantive requirements of the tariff provisions the ISO proposes to modify. Instead, the tariff changes simply clarify that *Constraint* means *Transmission Constraint* where the defined term is applicable, and

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[8] *See, e.g.*, proposed changes to section 27.4.3.2.

[9] *See, e.g.*, proposed changes to sections 8.3.3.2(g) and 27.1.2.1.

they eliminate any confusion created by use of the defined term *Constraint* where the ISO intended to use generic meaning of the lower-case word constraint. These proposed changes affect a number of tariff sections in the instant filing, which the ISO has cataloged in Attachment A.

Section 6.5.2.2.2

In section 6.5.2.2.2, the ISO proposes to clarify the time period during which scheduling coordinators may begin submitting bids in the day-ahead market for a specific trading day. This proposed change merely clarifies existing practice through the use of clearer language.

Section 6.5.4.2.2

The ISO proposes to clarify the time interval identified in section 6.5.4.2.2 for the publication of certain information relating to the hour-ahead scheduling process on the ISO's Open Access Same-time Information System (OASIS) site. Currently, section 6.5.4.2.2 states that the ISO will publish this information at thirty minutes before the trading hour. The ISO proposes to clarify that the information identified under section 6.5.4.2.2 needs to be published no later than forty minutes before the trading hour, rather than exactly thirty minutes before it. This proposed change will make Section 6.5.4.2.2 consistent with section 6.5.4.1.5 of the ISO tariff, which provides that the ISO must publish information relating to the hour-ahead scheduling process no later than forty minutes before the trading hour.

Section 7.3.3

In section 7.3.3, the ISO proposes to incorporate into its tariff by reference a business practice standard of the Wholesale Electric quadrant of the North American Energy Standards Board. This standard is titled Measurement and Verification of Wholesale Energy Demand Response (WEQ-015), 2008 Annual Plan Item 5(a), March 16, 2009. The Commission has required the incorporation of this provision into all open access transmission tariffs to facilitate, among other things, the participation by demand response resources in electricity markets.[10]

Section 7.7.8

The ISO proposes to revise section 7.7.8.1 and delete sections 7.7.8.1.1-7.7.8.4 of its tariff relating to the ISO's review, audit, and oversight of under-frequency load shedding programs for utility distribution companies and metered subsystems. WECC currently oversees and coordinates under-frequency load shedding programs in the

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[10] *Standards for Business Practices and Communication Protocols for Public Utilities*, 131 FERC ¶ 61,022 (2010).

Western Interconnection, including the ISO's balancing authority area.[11] The ISO, therefore, believes it is appropriate to make these revisions to its tariff.

Sections 8.3.1, *et al*.

The ISO proposes to modify section 8.3.1 to clarify its current practices for the procurement of long-term voltage support and black start capability. The current tariff reflects the ISO's procurement practices at the outset of the ISO's operations. These practices remain unchanged and the ISO proposes to clarify that they remain the current procurement practices.

The ISO also proposes to eliminate *Time Horizon* as a defined term and the use of that term throughout the tariff, including in section 8.3.1. In this filing, the ISO seeks to clarify a number of tariff sections, including section 8.3.1, to describe only the forward-looking time period in which a market process might issue a binding commitment or dispatch. The defined term *Time Horizon*, however, implies two different meanings. First, the term implies an applicable time period over which the ISO's market runs apply. Second, it implies a look-ahead time period of a particular market run, over which the market runs may or may not apply. Also, some tariff sections use the term *Time Horizon* to identify the time period in which a commitment could be binding, while other tariff sections use the term to identify non-binding look-ahead periods. This inconsistency in usage may create confusion among market participants. The ISO is not proposing to change the financially binding time periods but instead clarify the forward-looking periods of market runs, which incorporate additional information into that market run.

Accordingly, the ISO proposes to eliminate tariff references to the term *Time Horizon* that appear to describe non-binding look-ahead periods that have no direct impact on markets or schedules and are described in the ISO's Business Practice Manuals. For example, in section 8.3.1, the ISO proposes to delete the reference to the Real Time Unit Commitment (RTUC) Time Horizon with respect to the description of the amount of ancillary services that the ISO's market procures for an operating hour in the hour ahead scheduling process and real-time market. The current reference reflects a look-ahead period but not a time period in which the ISO makes a binding commitment to procure ancillary services. Instead, the ISO proposes to state in section 8.3.1 that the relevant period for the procurement of ancillary services in the real-time market is the 15 minute period to which the relevant RTUC process applies. In another instance, the ISO proposes to modify the definition of Security Constrained Unit Commitment (SCUC) to remove a reference to the term *Time Horizon* and to

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[11] *See* Section 6 of WECC Minimum Operating Reliability Criteria http://www.wecc.biz/Standards/WECC%20Criteria/WECC%20Reliability%20Criteria.pdf. *See also* standards development website for WECC-0065 Underfrequency Load Shedding Criterion: http://www.wecc.biz/Standards/Development/WECC-0065/default.aspx.

substitute a reference to the multiple hours over which SCUC determines commitment status, schedules, and other market procedures.

Attachment A hereto identifies and describes the proposed changes to the various sections of the tariff associated with deleting the defined term *Time Horizon*.[12] These changes clarify the tariff, without changing the applicable and financially binding time periods already contained in the tariff. Moreover, the ISO's proposed changes eliminate the unnecessary detail in the tariff regarding the look-ahead period that has no bearing on what time intervals apply to a market run. Finally, the ISO does not believe it is necessary to create a single term to refer to refer the collective financially binding time periods of the ISO's market runs as the proposed changes to the tariff also include the accurate applicable time periods that apply to each of the market runs described in the tariff.

Section 8.3.3.3

In section 8.3.3.3, the ISO proposes to clarify the time period at which it provides notice to market participants of forecasts of ancillary service requirements as well as minimum and/or maximum ancillary service regional limits. The current tariff states that the ISO will provide this information by 6:00 p.m. prior to the day-ahead market. The ISO is not proposing to change this requirement but instead to restate it to read that the ISO will provide this information by "6:00 p.m. on the day before the close of the" day-ahead market.

Section 8.10.8.1

In section 8.10.8.1, the ISO proposes to delete a reference to the day-ahead market as part of the requirement that system resources that receive ancillary services capacity awards must submit an e-tag associated with those awards. This amendment clarifies that the e-tag requirement applies to ancillary services capacity awards for system resources in any market interval (*e.g*., the day-ahead market or the hour-ahead scheduling process).

Section 9.3.6.5.1

The ISO proposes to delete section 9.3.6.5.1, which pertains to the calculation of aggregate generating capacity, because the section requires the ISO to gather data which the ISO does not use in connection with its current business practices. The section requires the ISO to use a long-range outage schedule to calculate annual, quarterly, and monthly aggregate peak generating capacity. The calculations required

12 *See, e.g.*, proposed changes to section 27.1.1 pertaining to locational marginal prices for energy; proposed changes section 27.4.1 pertaining to the security constrained unit commitment; proposed changes to section 27.4.2 pertaining to security constrained economic dispatch; and proposed changes to section 27.5.5 pertaining to load distribution factors.

by these provisions create a reporting obligation, but are not used for system planning or operation, in that the calculations incorporate outage requests already approved in accordance with section 9.3.6. Such information, moreover, may have little to no relevance given the implementation of the resource adequacy program that requires the advance procurement of capacity sufficient to achieve a defined planning reserve margin. The tasks outlined in section 9.3.6.5.1 are not necessary to the facilitation of the resource adequacy program or outage coordination.

Section 9.5

In section 9.5, the ISO proposes to revise requirements for maintaining information about outages. Specifically, the ISO proposes to move the current text of this section into section 9.5.1 and to add new section 9.5.2, which specifies what information the ISO will publish on its website with respect to generating units for which the ISO receives outage reports pursuant to the ISO tariff. Since 2001, the ISO has published to its website a list of "Curtailed and Non-Operational Generating Units" consistent with Section 352.5 of the California Public Utilities Code, but there has been no applicable tariff provision governing this activity. This new provision describes the ISO's longstanding practice, with one exception. It requires the ISO to publish the name of the scheduling coordinator of the unit. The ISO's prior practice was to publish the name of the owner of the generating unit. The purpose of this change is to provide a contact for persons who wish to inquire about the outage. The ISO consider a generating unit's scheduling coordinator as a more helpful contact than the direct owner of a generating unit - typically a limited liability company that owns the unit only.

Sections 10.2.8.2.1 and 10.2.8.2.2

In sections 10.2.8.2.1 and 10.2.8.2.2, the ISO proposes to clarify that scheduling coordinators may have access to the revenue meters of market participants they represent without the need for additional ISO approvals. This amendment is consistent with the intention of the *pro forma* meter service agreement set forth in Appendix B of the ISO tariff.

Section 11.5.2

In section 11.5.2, the ISO proposes to modify tariff language related to the settlement of uninstructed imbalance energy for metered subsystem operators. The proposed modifications restructure the tariff section to describe how the ISO calculates the settlement of uninstructed imbalance energy. The ISO also proposes to eliminate an outdated reference in the section to “resources within a System Unit” of metered subsystem operators. The ISO is not proposing to modify current settlement practices pursuant to this amendment but instead to use clearer language to describe the settlement of uninstructed imbalance energy for metered subsystem operators.

Section 11.5.6.2.5.1

In section 11.5.6.2.5.1, the ISO proposes modifications to clarify a reference in the tariff that might otherwise be construed to extend the allocation of exceptional dispatch excess cost payments to non-load-serving participating transmission owners. In the filing it submitted on December 16, 2009 regarding the transmission owner tariff of Trans Bay Cable LLC (Trans Bay Cable),[13] the ISO clarified that it intends to allocate exceptional dispatch excess cost payments only to participating transmission owners with service territories, which did not include Trans Bay Cable.[14] The Commission conditionally accepted Trans Bay Cable's transmission owner tariff subject to that clarification.[15] Based on the outcome of that proceeding, the ISO considers this amendment an appropriate clarification to its tariff.

Section 11.5.6.3.2

The ISO proposes to amend section 11.5.6.3.2 to delete tariff language that the ISO inadvertently did not delete as part of a compliance filing in the Amendment No. 60 proceeding. In that proceeding, the Commission determined that reliability must-run (RMR) contract service limits do not apply when the ISO issues an exceptional dispatch of an RMR Condition 2 unit since the exceptional dispatch is not an RMR dispatch.[16] Accordingly, the ISO is proposing to remove language from section 11.5.6.3.2 that addresses the allocation of start-up costs for an exceptional dispatch of a Condition 2 RMR unit because they exceed the scope of services provided under an RMR contract. This clarification will eliminate any ambiguity created by the ISO's existing tariff when read in conjunction with the Commission order in the Amendment No. 60 proceeding cited above.

Sections 11.5.6.4 and 34.9.2

Section 11.5.6.4 addresses the exceptional dispatch settlement price for incremental instructed imbalance energy that is consumed or delivered as part of exceptional dispatches for ancillary services testing. Section 34.9.2 specifies reasons for which the ISO may issue manual exceptional dispatches. The ISO proposes to

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13 *Trans Bay Cable LLC*, Commission Docket No. ER10-266-002.

14 Motion for Leave to Intervene Out of Time and Response to Comments of the California Independent System Operator Corporation, Docket No. ER10-266-000, at 3-4 (Dec. 16, 2009).

15 *California Independent System Operator Corp.*, 130 FERC ¶ 61,028, at P 26 (2010) ("We also direct Trans Bay to delete section 15 of the tariff since, as clarified by the CAISO and acknowledged by Trans Bay, Trans Bay will not be allocated any reliability services costs, including those costs associated with exceptional dispatches.").

16 *See California Independent System Operator Corp*., 108 FERC ¶ 61,022, at P 47 (2004).

modify sections 11.5.6.4 and 34.9.2 to clarify that exceptional dispatch authority also applies generally to periodic testing of resources.

Section 11.10.9.4

In section 11.10.9.4, the ISO proposes to clarify how it allocates rescinded ancillary services capacity payments among scheduling coordinators. The current tariff references an allocation methodology but does not specifically state the fact that this allocation methodology is based on the obligation of scheduling coordinators. For this reason, the ISO proposes to specify in section 11.10.9.4 that it will allocate rescinded ancillary service capacity payments to scheduling coordinators based on their ancillary service obligation[17] for the same trading day. This language is consistent with the ISO's current allocation practice.

Sections 11.19.1.2 and 11.19.3.4

The ISO proposes to modify section 11.19.1.2 to describe the settlement of FERC Annual Charges[18] on either a monthly or annual basis. Section 11.19.1.2 provides that "the FERC Annual Charges for a given Trading Month that are due monthly will be issued to Scheduling Coordinators twice a month in accordance with the CAISO Payments Calendar in the same Invoice and Payment Advice that contains the market Settlement and Grid Management Charge." Similarly, Section 11.19.1.2 provides that the "FERC Annual Charges for a given trading month that are due annually will be issued to Scheduling Coordinators twice a month on the same day as the market invoice and payment advice but in a separate Invoice as indicated in Section 11.29.10." The ISO seeks to clarify these provisions so that they clearly state that for scheduling coordinators that elect to pay the FERC Annual Charges monthly, their charges will continue to appear in the same invoice and payment advice as the market settlement and grid management charge issued twice a month. These changes do not substantively change the issuance of the FERC Annual Charges for scheduling coordinators that elect to pay monthly. Similarly, the ISO proposes to clarify that for scheduling coordinators that elect to pay these charges annually, the charges will appear on the same day as the invoice and payment advice as the market settlements and grid management charges, but on a separate invoice. Finally, the ISO proposes to add a sentence to section 11.19.1.2 to state that the ISO will provide scheduling coordinators with information on their FERC Annual Charges at least twice a month.

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[17] ISO tariff, Appendix A, Master Definitions Supplement defines Ancillary Services Obligation as follows: "A Scheduling Coordinator's hourly obligation for Regulation Down, Regulation Up, Spinning Reserves, and Non-Spinning Reserves calculated pursuant to Section 11.10.2.1.3, 11.10.2.2.2, 11.10.3.2, and 11.10.4.2, respectively."

[18] ISO tariff Appendix A Master Definitions Supplement defines FERC Annual Charges as follows: "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."

Currently, the ISO settlements systems issue settlements statements with these amounts daily. These proposed changes do not alter the requirements already set forth in section 11.19.1.2.

In section 11.19.3.4, the ISO proposes to add language to eliminate any potential ambiguity concerning the allocation of a surcharge (associated with under-recovery of FERC Annual Charges) or a payment (associated with over-recovery of FERC Annual Charges). As clarified in revised section 11.19.3.4, the ISO allocates these surcharges or payments to scheduling coordinators based on the percentage of the surcharge or credit that reflects the active scheduling coordinators' metered demand and exports during the relevant year.

Section 11.21.1

The ISO proposes to clarify in section 11.21.1 the difference between day-market and real-time market shortfalls for calculated locational marginal prices in its market validation and price correction process described in section 35 of its tariff. The purpose of this proposed amendment is to ensure consistency with tariff language previously accepted in another Commission proceeding. On March 31, 2010, the ISO filed proposed tariff provisions in Docket No. ER10-966 that provide a mechanism to protect scheduling coordinators from adverse financial impacts in cases when prices are subsequently corrected in a way that is not consistent with their accepted demand bids.[19] This "make-whole" mechanism applies to all demand, including internal demand and exports, cleared in the integrated forward market, and all export schedules cleared in the hour-ahead scheduling process. In the event the ISO conducts a price correction such that market clearing prices are adjusted upward, cleared demand schedules affected by the price correction will not be settled at the corrected price, but will instead be settled an alternative derived price. This approach ensures that a scheduling coordinator is not adversely impacted by a subsequent price correction that results in a price above its accepted bid prices.

On April 21, 2010, Southern California Edison Company filed comments in Docket No. ER10-966 requesting that the ISO clarify in the tariff that any revenue shortfalls as a result of the application of this make-whole methodology will be captured through the allocation of non-zero amounts of the sum of imbalance energy, uninstructed imbalance energy, and unaccounted for energy in the real-time in accordance in section 11.5.4 of the ISO tariff. The ISO amended its filing in Docket No. ER10-966 on May 13, 2010 to include this clarification in the tariff by adding the following statement to the end of section 11.21.1:

> Any non-zero amounts in revenue collected as a result of the application of the Price Correction Derived LMP will be captured

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[19] *See* ISO Transmittal Letter, filed March 31, 2010 in FERC Docket No. ER10-966-000.

> through the allocation of non-zero amounts of the sum of Imbalance Energy, Uninstructed Imbalance Energy, and Unaccounted for Energy in accordance with Section 11.5.4.

On May 27, 2010, the Commission issued a letter order in which it accepted the ISO's March 31 filing as amended on May 13. In these filings, however, the ISO failed to distinguish between the day-ahead and real-time shortfalls. The day-ahead shortfalls under the ISO market are ultimately resolved through the calculation of the integrated forward Market Congestion Charge described in section 11.2.4.1 and not the real-time imbalances described in section 11.5.4. The ISO now proposes to clarify section 11.21.1 of its tariff to distinguish between the day-ahead and real-time shortfalls. Specifically, the ISO proposes to add the following underlined language to the above sentence contained in section 11.21.1:

> Any non-zero amounts in revenue collected as a result of the application of the Price Correction Derived LMP will be captured through the <u>calculation of the IFM Congestion Charge reflected in Section 11.2.4.1 and the</u> allocation of non-zero amounts of the sum of Imbalance Energy, Uninstructed Imbalance Energy, and Unaccounted for Energy in accordance with Section 11.5.4.

<u>Section 11.22.2.5.8 and Appendix F</u>

In section 11.22.2.5.8 and Appendix F, Schedule 1, Part A, the ISO proposes to clarify that the settlements, metering, and client relations charges apply only to active scheduling coordinators in a given trading month. The proposed changes specify that these charges apply to scheduling coordinators with scheduling coordinator ID codes with a non-zero invoice value where the non-zero value reflects market activity in the current trading month.

<u>Section 11.29.7.1</u>

Section 11.29.7.1 of the ISO tariff describes the timing for the issuance of settlement statements. The ISO proposes to amend this section to clarify what happens when, for whatever reason, any of the applicable settlement statements are issued after the specified times. While late or failed issuances do not occur frequently, a statement may occasionally be issued after the designated time due to system issues or human error. Because the settlement dispute time lines in the tariff are tied to the timeframe in which settlement statements are issued, it is important for market participants to track when the issuance of settlement statements occurs. The ISO's practice has been to notify market participants of late issuances and the impact on the dispute windows pursuant to guidelines contained in the *Provisions for Late and Reposting Statement File Components* posted on the ISO website.[20] Therefore, the

[20] *See* http://www.caiso.com/279b/279bcad34eb20.pdf.

ISO proposes to add language to section 11.29.7.1 that clarifies that the ISO will notify affected market participants regarding failed or late publication of any settlement statements specified in this section and will rectify such failed or late publications pursuant to its procedure posted on the ISO website.

<u>Section 11.29.7.3.4</u>

Section 11.29.7.3.4 addresses the issuance of invoices for activities outside of monthly market activities. These include recalculated settlement statements, post-closing adjustments, and the financial outcomes of alternative dispute resolution procedures or other dispute resolutions. The ISO proposes to replace the reference to *Re-runs* with *Recalculation Settlement Statements* in the first sentence of section 11.20.7.3.4 and to include a reference to section 11.20.10.3. The ISO also proposes to delete the second sentence from this section. The purpose of these changes is to clearly identify for what activities the ISO may invoice separately from monthly market activities and to align the provisions of this section with the provisions 11.29.10.3, which governs in part the notice requirements for identifying the components of any such invoice or payment advice.

<u>Sections 11.29.9.6.1, 11.29.10.6, and 11.29.11</u>

In sections 11.29.9.6.1, 11.29.10.6, and 11.29.11, the ISO proposes to allow for adjustments on invoices in the event of a verifiable error that the ISO would reverse in a future invoice. The proposed tariff changes authorize the ISO to instruct a scheduling coordinator or CRR holder not to remit payment for a specific charge shown on an invoice, if the ISO identifies a verifiable error that it would reverse on a future invoice. The provisions specify that this occurrence will not constitute a payment default under the ISO tariff. The ISO proposes these changes to address situations such as those underlying an earlier ISO request in another proceeding for a limited tariff waiver to resolve an inadvertent data entry error that resulted in an erroneous charge to the City of Riverside.[21] In order to resolve such an invoicing error, it is more efficient for the ISO to instruct a scheduling coordinator or CRR holder to not remit the charge.

<u>Section 22.4.1</u>

Section 22.4.1 specifies the permissible means of sending any notice, demand, or request in accordance with ISO tariff. The provision states that any notice shall be in writing and specifies methods of delivery. The ISO proposes to modify section 22.4.1 to identify electronic mail as a permissible means to effect delivery of a notice, demand, or request under the ISO tariff upon receipt of conformation by return email. This proposed tariff change is consistent with modern business practices. At the

[21] *See California Independent System Operator Corp*., 132 FERC ¶ 61,004 (2010).

suggestion of one stakeholder, the ISO intends to issue a market notice to inform market participants of this means of delivery if the Commission accepts the proposed change.

<u>Section 22.4.3</u>

Section 22.4.3 sets forth the notice provisions for changes in the ISO's Operating Procedures and Business Practice Manuals. While the ISO provides notice of changes to both Operating Procedures and Business Practice Manuals, the current tariff specifies that changes to Operating Procedures and Business Practice Manuals each require at least 30 day's advance notice. This provision reflects an inadvertent error. While the minimum 30 days' advance notice applies to a proposed change to a Business Practice Manual, it should not apply to Operating Procedure changes. Changes to Operating Procedures may require shorter notice periods and in some cases notice after-the-fact. Therefore, the ISO is proposing to modify this section to remove the 30-day advance notice requirement for changes to Operating Procedures, although the section will still require the ISO to provide notice of any changes to Operating Procedures. The ISO is also proposing to clarify in this section a potential ambiguity concerning what notice period applies to proposed changes to clarify existing business practice manual language, correct grammatical errors, and make revisions with minor significance. Under section 22.11.1.4(a), these changes may be effective at any time after the applicable comment period expires. The ISO's revisions to section 22.4.3 clarify this potential ambiguity.

<u>Sections 25.1 and 25.1.2</u>

The ISO proposes to revise sections 25.1 and 25.1.2 to clarify the tariff provisions governing the application of the ISO's interconnection procedures once a generating unit's prior power sales arrangements to a participating transmission owner or on-site customer have terminated. The ISO's proposed changes make clear that these procedures apply to all generating units, not just qualifying facility generating units. Moreover, the proposed changes clarify that the owner of a generating unit must describe through supporting information any change to the total capability or electrical characteristics of the generating unit in order to allow the participating transmission owner and ISO to assess whether the owner must become an interconnection customer under the ISO tariff.

<u>Section 26.5 and Appendix F</u>

The ISO proposes to revise section 26.5 and Appendix F to address the conclusion of the transmission access charge transition period. The ISO tariff defines this period as "the 10-year transition period for the CAISO's Access Charge methodology commencing January 1, 2001 through December 31, 2010."[22] The ISO's

[22] *See* ISO tariff, Appendix A, Master Definitions Supplement, definition of *TAC Transition Period*.

proposed changes specify that the provisions of section 26.5 and Appendix F that currently determine the ISO's transmission access charges cease to apply at the end of the transition period.

Sections 30.5.2.1 and 30.5.2.2

The ISO proposes to revise sections 30.5.2.1 and 30.5.2.2 to clarify the necessary components of supply bids as well as supply bids for participating generators. Specifically, the ISO proposes to modify the tariff language to require scheduling coordinators to submit additional information regarding the identification characters assigned by the ISO to the resource associated with the supply bid. The proposed language also clarifies that scheduling coordinators need only submit identified bid components, if they apply.

Sections 30.5.2.7, 30.5.3, 31.5.1.2, and 40.7.3

Under the current ISO tariff, scheduling coordinators have an affirmative duty to bid resource adequacy capacity into the residual unit commitment process. The ISO proposes several revisions to sections 30.5.2.7, 30.5.3, 31.5.1.2, and 40.7.3 to reflect the fact that the ISO scheduling infrastructure and business rules system is now capable of generating residual unit commitment availability bids for resource adequacy capacity and interim capacity procurement mechanism capacity. Accordingly, it is no longer necessary for a scheduling coordinator to submit such bids. The ISO's proposed tariff changes remove this obligation from the tariff.

Sections 30.7.3.1, 30.7.6.1, and 40.6.8

The ISO proposes to clarify the bid extension rules contained in sections 30.7.3.1, 30.7.6.1, and 40.6.8. These tariff clarifications provide a greater degree of granularity regarding the circumstances in which the ISO's market software will insert an ancillary services or energy bid on behalf of a resource.

The ISO's proposed modifications to these sections clarify that the ISO will not submit a companion spin or non-spin bid at $0 in the real-time market, if a resource submits an energy bid and a spin or non-spin bid. This revision is consistent with existing tariff language in section 30.7.6.1, which states: "To the extent that an Energy Bid to the HASP/RTM is not accompanied by an Ancillary Services Bid, the CAISO will insert a Spinning Reserve and Non-Spinning Reserve Ancillary Services Bid at $ 0/MW for any certified Operating Reserve capacity." The ISO believes it is helpful to clarify for market participants that it will not submit a bid at $0/MW for any certified operating reserve capacity if a resource submits an energy bid and an ancillary service bid. This change will provide certainty to market participants of the circumstances in which the ISO will submit a $0/MW bid in the real-time market for certified operating reserves.

The ISO also seeks to align its tariff with its scheduling infrastructure business rules process, which treats a partial energy bid that accompanies a submission to self-provide ancillary services as a signal that the scheduling coordinator does not have sufficient capacity available to satisfy its submission to self-provide ancillary services. For this reason, the ISO is proposing to amend section 30.7.3.1 to state that it will not extend an energy bid under these circumstances.

Finally, the ISO proposes to clarify the tariff provisions to state that the ISO may insert a bid in the real-time market required under section 40 for a resource adequacy resource that is also use limited, if the resource submits an energy bid and fails to submit an ancillary service bid. This modification clarifies existing tariff language, which could otherwise be construed as preventing the ISO from optimizing a use-limited resource adequacy resource between energy and ancillary services, if the resource submits an energy bid but fails to submit an ancillary service bid.

Section 36.13.6

Section 36.13.6 specifies the means of calculating the market clearing price for CRRs cleared through the ISO's CRR auction. The ISO proposes to clarify section 36.13.6 to state that the price per megawatt for a specific CRR will equal the nodal price at the applicable CRR Source minus the nodal price at the CRR Sink, as opposed to the CRR Sink minus the CRR Source. The proposed tariff revisions do not change the fact that the price is based on the difference of the same two numbers. Therefore, the proposed revisions do not alter the calculated price. But the revised language more accurately reflects how the price for purchasing or selling a CRR is actually calculated through the ISO's systems.

Section 36.15

Section 36.15 includes language to address the reduction and refund of any firm transmission rights (FTRs) issued for 2009-2010. FTRs are not used in the ISO's new markets based on locational marginal pricing. The ISO actually reduced and refunded any outstanding FTRs as of July 2009, The ISO, therefore, proposes to delete section 36.15 because it is no longer necessary.

Section 37.2.1.1

Section 37.2.1.1 requires market participants to comply with ISO operating orders. The ISO proposes to modify the section to clarify that deviation from an automatic dispatch instruction shall not constitute a violation of this section. The ISO recognizes that a deviation from a dispatch instruction should not in itself result in a sanction, and has not sought to impose sanction where such conduct occurs. This clarification will provide market participants with greater certainty that they will not face penalties under section 37.2 when they deviate from an automatic dispatch signal.

Sections 37.5.2.1, 37.9.3.1, and 37.11.1

Sections 37.5.2.1, 37.9.3.1, and 37.11.1 address rules of conduct for the submission of meter data, administration of penalties, and the method of calculating meter data penalties. The ISO proposes to revise the applicable timelines under these sections to conform to payment acceleration timelines approved by the Commission in 2009 and incorporated into the ISO's payments calendar.[23] The ISO proposes to clarify section 37.5.2.1 to state that market participants must correct any errors in settlement quality meter data no later than 43 calendar days after the trading day. The ISO also proposes changes to section 37.9.3.1 to clarify when the ISO intends to administer penalties, either through initial settlement statements issued seven business days after the trading day to recalculation settlement statement. Finally, in section 37.11.1, the ISO is proposing to clarify that error in submitted meter data that exists 43 calendar days after the trading day constitute a violation of the rules of conduct. Throughout section 37.11.1 as listed in Attachment A hereto, the ISO also proposes to clarify its explanation of how it calculates inaccurate meter data penalties.

Sections 39.6.1.6.1 and 39.7.1.1.1.

The ISO proposes to modify sections 39.6.1.6.1 and 39.7.1.1.1 to change provisions related to the gas price component of projected proxy costs of start-up and operating at minimum load for natural gas-fired resources. In section 39.6.1.6.1, the ISO proposes to delete references to NYMEX because the exchange was sold. The ISO proposes to modify section 39.7.1.1.1 to reflect the names of publications and timing of publications used to determine the gas price index for purposes of calculating incremental fuel costs for default energy bids based on fuel costs and variable operations and maintenance costs of natural gas-fired resources. The modifications also clarify that ISO will publish a single gas price index each day while using the most recent gas price index published for each market application (*i.e.*, the real-time market will use a more recent gas price index than the prior day-ahead market) and to clarify that the ISO will use the most recent available gas price if a gas price index is unavailable for any reason.

Section 39.7.1.2

Section 39.7.1.2 explains how the ISO calculates default energy bids used in the ISO's local market power mitigation process based on a weighted average of locational marginal prices. The ISO proposes to amend this section to clarify that the ISO will use locational marginal prices that passed the price validation and correction process set forth in section 35 of the tariff to calculate default energy bids. This amendment does not change existing ISO practices for using locational marginal prices to calculate default energy bids.

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23 *See California Independent System Operator Corp.*, 128 FERC ¶ 61,265 (2009).

Section 40.3.1.2

Section 40.3.1.2 contains a table that identifies contingencies that the ISO uses in connection with its local capacity technical study to identify local capacity areas, determine the minimum amount of local capacity area resources in MW that must be available to the ISO within each identified local capacity area, and identify the generating units within each identified local capacity area.[24] The ISO proposes to revise this table to remove information that was inadvertently included in it and which the ISO does not assess as part of its contingency studies.

Section 43.1.2.1

In section 43.1.2.1, the ISO proposes to delete language related to the time frame for issuing a market notice that identifies a deficiency in a local capacity area as assessed by the ISO's local capacity technical study. Specifically, the ISO is proposing to delete language that requires the ISO to issue such a notice 60 days before the beginning of a resource adequacy compliance year[25] and allows scheduling coordinators to submit a revised resource adequacy plan within 30 days of any market notice as opposed to linking the submission of revised resource adequacy plans to the beginning of the resource adequacy compliance year. The ISO believes these revisions more appropriately align the tariff provisions regarding this cure period with the resource adequacy program objectives.

Section 44

The ISO proposes to delete section 44 from its tariff. This section addresses the ISO's authority to suspend its current tariff during the first 30 days of operation of its new market. This time period expired at the end of April 2009. Accordingly, the ISO believes it is appropriate to remove section 44 from its tariff.

Appendix A

In Appendix A of its tariff, the ISO proposes to modify the definitions of a number of terms. Many of these changes are self-explanatory or are related to the proposed amendments described above. The ISO has provided explanations for each definitional change in Attachment A hereto.

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24 *See* ISO tariff, section 40.3.1.

25 Appendix A of the ISO's tariff defines the resource adequacy compliance year as "[a] calendar year from January 1 through December 31."

Appendix B

The ISO proposes to make changes to Appendix B, which includes various *pro forma* agreements. These proposed changes include the modification of provisions in Appendices B.8, B.9, and B.10 to remove the requirement that parties include confidential operational contact information in the ISO's *pro forma* agreements. The purpose of these amendments is to reduce the possibility of accidental disclosure and reduce the need to file confidential information with the Commission.

Appendix F

The ISO proposes to make changes to Appendix F, which includes various rate schedules. These proposed changes include the deletion of Part F of Schedule 1 of Appendix F because the provisions of that part no longer apply. The provisions address charges for inter-scheduling coordinator trades submitted by Pacific Gas and Electric Company in its role as Path 15 facilitator. Pacific Gas and Electric Company no longer serves in this role. The ISO therefore believes it is appropriate to remove this provision from its tariff.

Appendix P

The ISO proposes to make a number of minor changes to Appendix P of its tariff, which pertains to the ISO's Department of Market Monitoring ("DMM"). These proposed changes include the deletion of a reference in section 5.1.7 of Appendix P to referral under section 12 of Appendix P in instances in which the ISO disagrees with the DMM regarding a proposed market rule, tariff change, or market design change. The ISO is proposing to delete the reference to section 12 of appendix P because that section describes the procedures for a DMM referral to the Commission, whereas Appendix P, Section 5.1.7 deals with the ISO's reporting obligation to the Commission.

III. Stakeholder Process

The ISO initiated a process to obtain stakeholder input concerning the proposed tariff changes in this filing on November 9, 2010. The ISO accepted written comments on the proposed changes and held two conference calls with stakeholders to discuss questions and stakeholder comments. The ISO has posted on its website a matrix of stakeholder comments as well as the ISO's responses.[26] The ISO believes that stakeholders do not oppose the tariff amendments proposed in this filing. In many cases, the ISO has incorporated proposed changes from stakeholder comments.

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[26] A record of the ISO's stakeholder process, comments received and ISO responses to comments is available at the following website: http://www.caiso.com/2848/2848eb6213120.html.

During the stakeholder process, some stakeholders requested how they might propose additional clarifications to the ISO tariff not included in this filing. Stakeholders also asked specific questions regarding tariff sections that the ISO did not propose to amend. To the extent proposed changes initiated by stakeholders do not create substantive changes in rates or terms and conditions of service, stakeholders may raise these proposals in future tariff clarification initiatives. In addition, stakeholders can raise more significant issues or questions with their ISO client representatives or through the ISO's quarterly market performance and planning forum. The ISO looks forward to working in collaboration with stakeholders on future tariff clarification efforts.

IV. Effective Date

The ISO requests an effective date of February 28, 2011 for the tariff provisions submitted with this filing.

V. Materials Provided In This Compliance Filing

The following documents, in addition to this transmittal letter, support this filing:

Attachment A	Key to proposed tariff changes
Attachment B	Clean sheets of the currently effective tariff showing revisions described in this filing
Attachment C	Sheets showing, in black-line format, the changes to the currently effective tariff described in this filing

VI. Communications

Communications regarding this filing should be addressed to the following individuals, whose names should be placed on the official service list established by the Secretary with respect to this submittal:

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VII. Service

The ISO has served copies of this transmittal letter, and all attachments, on the California Public Utilities Commission, the California Energy Commission, and all parties with effective scheduling coordinator service agreements under the ISO tariff. In addition, the ISO is posting this transmittal letter and all attachments on the ISO website.

VIII. Conclusion

In this filing, the ISO is proposing amendments to its tariff to clarify the meaning of existing tariff provisions, ensure consistency throughout the tariff as well as between the tariff and business practices, and correct typographical and other inadvertent errors. The ISO respectfully requests that the Commission accept this tariff amendment as filed.

Please do not hesitate to contact the undersigned if you have any questions.

Respectfully submitted,

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Section or Appendix	Reason
1.3.2(f)	This amendment clarifies that if an ISO protocol and a section of the tariff conflict, the provisions of the tariff will control to the extent of the inconsistency.
4.3.1.2	This amendment makes a grammatical change to section 4.3.1.2.
4.5.1.3	This amendment makes a typographical change to section 4.5.1.3.
4.5.3.2.2	This amendment capitalizes the defined term "Interchange Schedules".
4.5.3.7	This amendment deletes this section in its entirety because the provisions of this section have been displaced by resource adequacy provisions in Section 40.
4.6	This amendment clarifies the circumstances under which a generator with a generating unit in the ISO balancing authority area must enter into an agreement with the ISO to establish the terms associated with its obligation to submit bids, including self-schedules, to the ISO. This clarification reflects the ISO's past practice in applying this tariff provision.
4.6.3.1	This amendment clarifies the circumstances under which a generator with a small generating unit may be exempt from compliance with ISO tariff requirements applicable to participating generators. This clarification is a companion to the revisions to the definition of *Participating Generator* in Appendix A of the ISO tariff and both conform to the similar tariff revisions filed by the ISO in Docket No. ER10-1755. These revisions also provide a clarification reflecting the ISO's past practice of excluding very small generating units from participation in its markets.
4.6.5	This amendment changes the heading of section 4.6.5 to reflect that North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) standards and criteria apply to Participating Generators.
4.6.5.1	This amendment supplements the requirement that participating generators comply with WECC standards by the addition of a reference to the need for participating generators to comply with all Applicable Reliability Criteria. NERC has developed reliability standards and may develop others that in some cases supersede the requirements for participating generators previously established by WECC.
4.6.5.2, 4.6.5.3	These amendments delete the provisions of Sections 4.6.5.2 and 4.6.5.3 pursuant to the letter dated September 29, 2010 from WECC notifying the ISO of its intent to terminate its Reliability Management System (RMS) agreement and associated reliability criteria agreement with the ISO. On October 11, 2010, WECC also filed with the Commission a notice of proposed cancellation of its RMS agreement originally filed in Docket No. ER99-3396-000. WECC has represented in its letter to the ISO that the RMS served as a predecessor to the mandatory reliability standards approved

Section or Appendix	Reason
	by the Commission under its authority pursuant to section 215 of the Federal Power Act and that the Commission's approval of these standards has rendered the RMS redundant for users, owners, and operators of the bulk power system in the United States. In its notice of proposed cancellation filed with the Commission, WECC has made a similar representation that the RMS has been rendered obsolete. The provisions of Sections 4.6.5.2 and 4.6.5.3 incorporate requirements applicable to generators intended to bind the generators to comply with reliability criteria agreements pursuant to WECC RMS requirements applicable to generators. The ISO has incorporated this requirement into the tariff for no purpose other than to satisfy the requirements of its own RMS agreement with WECC. As the ISO's RMS agreement with WECC will terminate, and as WECC has represented that the RMS is redundant to the mandatory reliability standards and is obsolete, the ISO sees no further purpose in requiring generators to comply with WECC requirements for generators set forth in Sections 4.6.5.2 and 4.6.5.3. For this reason, the ISO proposes to delete the provisions of these sections from the tariff.
4.10.1.5.1	These amendments clarify that a Candidate Congestion Revenue Rights Holder must provide information about its affiliates as part of its application process. These amendments also make a typographical change to section 4.10.1.5.1.
4.10.2.2	This amendment corrects an inaccurate section cross-reference in the tariff.
6.5.1.1.1(b), 6.5.1.1.2(b)	These amendments substitute the defined term *Constraints* with a new defined term *Transmission Constraints*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints*. The ISO also intends to refer to constraints in other sections of the tariff pursuant to the plain meaning of that word.
6.5.2.1(b)	This amendment makes a typographical correction to section 6.5.2.1(b).
6.5.2.2.2	This amendment clarifies that the window to submit bids for the day-ahead market opens seven days prior to the Trading Day.
6.5.3.2.1	This amendment makes a typographical correction to section 6.5.3.2.1.
6.5.3.2.2(i)	This amendment substitutes the defined term *Constraints* with a new defined term *Transmission Constraints* and changes a reference to *transmission Constraints* to the defined term *Transmission Constraints*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints*.
6.5.3.3	This amendment changes a reference to *transmission Constraints* to the defined term *Transmission Constraints*. The definition for the term *Transmission Constraints* will be

Section or Appendix	**Reason**
	the same as the current definition of the term *Constraints*. This amendment also makes typographical changes to reflect to use of defined terms in this section.
6.5.4.2.2	This amendment changes the time period to post information related to the hour ahead scheduling process to the ISO's open access same-time information system from "at thirty (30) minutes" to "No later than forty (40) minutes." This amendment aligns section 6.5.4.2.2 with the time period set forth in Section 6.5.4.1.5, which also requires the ISO to post certain information related to the hour ahead scheduling process and clarifies that the ISO does not need to publish the data specified in 6.5.4.2.2 at an exact time before the Trading Hour.
6.5.6.1.1	This amendment changes the time period to publish information relating to ancillary service market bids, energy market bids and residual unit commitment market bids on the ISO's open access same-time information system. The amendment makes section 6.5.6.1.1 consistent with the disclosure requirements set forth in section 20.4 of the ISO's tariff.
6.5.7	This amendment changes a reference to *transmission Constraints* to the defined term *Transmission Constraints*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints*.
7.3.3	This amendment incorporates by reference a North American Energy Standards Board business standard into the ISO's tariff as required by Commission Order No. 676-F.
7.7.8.1	This amendment modifies this tariff section because WECC (and not the ISO) oversees the under-frequency load shedding program.
7.7.8.2	This amendment deletes this tariff section because WECC (and not the ISO) oversees the under-frequency load shedding program.
7.7.8.3	This amendment deletes this tariff section because WECC (and not the ISO) oversees the under-frequency load shedding program.
7.7.8.4	This amendment deletes this tariff section because WECC (and not the ISO) oversees the under-frequency load shedding program.
7.7.15.4	This amendment makes a typographical change to section 7.7.15.4.
8.3.1	This amendment eliminates reference to the real time unit commitment *Time Horizon* and now provides that the relevant period for the procurement of ancillary services in the real-time market is the 15 minute period to which the relevant real time unit commitment applies. This amendment also revises this tariff section to reflect current

Section or Appendix	**Reason**
	procurement practices for voltage support and black start.
8.3.3.2	This amendment replaces the words "look to" with the word "use" to clarify the factors that the ISO will rely on to establish minimum and maximum procurement limits in the ancillary services sub-regions. This amendment also changes the inadvertent use of the defined term *Constraints* to the word *constraints*. In this section, the ISO intends to refer to the plain meaning of the word constraints as opposed to only "physical and operational limitations on the transfer of electrical power through transmission facilities." (*See*, ISO proposed definition for *Transmission Constraints*.)
8.3.3.3	This amendment clarifies the timeframe in which the ISO publishes forecasted ancillary service requirements, regional constraints and the minimum and/or maximum ancillary service regional limits.
8.3.3.5	This amendment changes the use of the words *network constraints* in this section to the new defined term *Transmission Constraints.*
8.9.3.1	This amendment capitalizes the defined term *Interchange Schedule*.
8.9.15.2	This amendment clarifies the appropriate references to sections of the ISO tariff for the consequences of failure of an ancillary services or residual unit commitment capacity performance audit.
8.10.8.1	This amendment deletes references to the day-ahead market because the e-tag requirement referenced in this section applies to ancillary service awards in the day-ahead market as well as the hour ahead scheduling process.
9.3.6.5.1	This amendment removes provisions that require the ISO to gather data which relate to outage coordination but which the ISO does not use in connection with current business practices.
9.3.10.6	This amendment corrects an inaccurate section cross-reference and makes a typographical change to section 9.3.10.6.
9.5, 9.5.1, 9.5.2	These amendments change tariff provisions concerning the ISO's publication of information concerning generating unit outages. Since 2001, the ISO has published to its website a list of "Curtailed and Non-Operational Generating Units" consistent with Section 352.5 of the California Public Utilities Code, but there has been no applicable tariff provision governing this activity. These new provisions describe the ISO's longstanding practice, with one exception. They require the ISO to publish the name of the scheduling coordinator of the unit. The ISO's prior practice was to publish the name of the owner of the generating unit. The purpose of this change is to provide a contact for persons who wish to inquire about the outage. The ISO considers a

Section or Appendix	Reason
	generating unit's scheduling coordinator as a more helpful contact than the direct owner of a generating unit - typically an LLC that owns the unit only. These amendments also clarify that the ISO may publish this information but that it should not publish information about generators within the state of California that do not provide that information to the ISO under the tariff or a contract.
10.2.8.2.1. 10.2.8.2.2	These amendments clarify that a scheduling coordinator may access the revenue meters of the market participants it represents without the need for additional ISO approval. These amendments also specify that the ISO's approval to access a market participant's revenue meter is set forth in the Meter Service Agreement for ISO metered entities.
10.3.6.2(c)	This amendment makes a typographical correction to section 10.3.6.2 (c).
10.3.6.3	This amendment makes a typographical correction to section 10.3.6.3.
11.1.5(b)	These amendments make typographical changes to section 11.1.5(b).
11.2.4.5	This amendment corrects usage of defined terms in this section.
11.2.5.1	This amendment corrects a section cross-reference in section 11.2.5.1.
11.5.1, 11.5.1.1, 11.5.1.2	These amendments make typographical corrections to section 11.5.1, 11.5.1.1, and 11.5.1.2
11.5.2	This amendment clarifies a potentially unclear provision of the tariff by deleting an outdated reference to resources within a System Unit of an MSS Operator in the in relation to the current provisions of this section. This amendment also restructures the tariff section to describe how the ISO calculates the settlement of uninstructed imbalance energy.
11.5.6.2.5.1	This amendment clarifies a reference in the tariff that might have been construed to extend the allocation of exceptional dispatch excess cost payments to non-load-serving participating transmission owners. In its December 16, 2009 filing in the Commission's proceeding on the transmission owner tariff of Trans Bay Cable (*Trans Bay Cable LLC*, Commission Docket No. ER10-266-002), the ISO clarified that it intends to allocate exceptional dispatch excess cost payments only to participating transmission owners with service territories.
11.5.6.3.2(b)	This amendment deletes language that should have been deleted in the ISO's filing made in compliance with the July 8, 2004 order in the Amendment 60 proceeding, Commission Docket No. ER04-835. (*See*, *California Independent Sys. Operator Corp.*, 108 FERC ¶ 61,022 (2004) at P 47.)

Section or Appendix	Reason
11.5.6.4	This amendment clarifies that exceptional dispatch authority applies generally to periodic testing of resource, including Pmax testing and pre-commercial operation testing.
11.8.6.5.3(i)	This amendment corrects the use of a defined term.
11.10.1.4	This amendment makes the reference to exceptional dispatch settlement rules in Section 11.5.6 more general.
11.10.3.2	This amendment makes typographical changes to section 11.10.3.2.
11.10.9.4	This amendment clarifies the ISO's current allocation methodology for rescinded ancillary service capacity payments.
11.13.10	This amendment corrects a section cross-reference in the section 11.13.10.
11.19.1.2	This amendment clarifies how the ISO issues FERC annual charges in settlement statements.
11.19.3.4	This amendment makes typographical changes to section 11.19.3.4 and clarifies that the ISO allocates any surcharge or payment related to the recovery of FERC annual charges to scheduling coordinators based on their metered demand and exports.
11.19.4	This amendment makes a typographical change to section 11.19.4.
11.20.5	This amendment makes a typographical change to section 11.20.5.
11.20.7.3	This amendment corrects a typographical error in section 11.20.7.3.
11.21.1	This section currently describes the financial implications of the calculation of the price corrections make-whole payments for demand and exports in the real-time market. This amendment corrects a typographical error in section 11.21.1 and distinguishes between day-ahead and real-time shortfalls as part of the calculation of the IFM Congestion Charge described in section 11.2.4.1 for purposes of protecting scheduling coordinators from adverse financial impacts in cases when prices are subsequently corrected in a way that is not consistent with their accepted demand bids.
11.22.2.5.8	These amendments clarify that the settlement, metering and client relations charge identified in this section applies only to active scheduling coordinator ID codes in a given month.
11.29.5.2	This amendment makes a typographical correction to section 11.29.5.2.

Section or Appendix	Reason
11.29.7.1	This amendment clarifies how the ISO will address the late publication of settlement statements.
11.29.7.1.1, 11.29.7.1.2	These amendments correct typographical errors in section 11.20.7.1.1 and 11.20.7.1.2.
11.29.7.3.4	This amendment makes this section's provisions consistent with the provisions of section 11.29.10.3, which governs in part the notice requirements for identifying the components of any invoice or payment advice that addresses activities separate from monthly market activities.
11,.29.9.6.1(a), 11.29.10.6, 11.29.11	These amendments allow the ISO to instruct a market participant not to pay an erroneous charge. These amendments address situations such as those underlying the limited tariff waiver to address an inadvertent data entry error that resulted in an erroneous charge to the City of Riverside. (*See*, *California Independent System Operator Corp*. 132 FERC ¶ 61,004 (2010).) If the ISO verifies an error that it would reverse on a future invoice, this amendment will allow the ISO to instruct a scheduling coordinator or congestion revenue rights holder not to remit payment for a specific charge shown on that invoice that results from the error.
11.31.1	This amendment corrects the use of a defined term in Section 11.31.1.
12.1.3.1.1	This amendment makes a typographical correction to Section 12.1.3.1.1.
12.5.1(b)	This amendment makes a typographical correction to Section 12.5.1(b).
13.5.2	This amendment corrects the use of an outdated term.
14.5.2	This amendment corrects a typographical error in section 14.5.2.
19	This amendment deletes this section in its entirety because the provisions of this section have been displaced by resource adequacy provisions in Section 40.
20.4(e)(i)	This amendment corrects the use of defined terms and grammar.
20.4(e)(ii)	This amendment corrects an incorrect section cross-reference and correct punctuation.
22.4.1	This amendment allows any notice, demand or request in accordance with the ISO tariff to be provided by e-mail with confirmation by return e-mail.
22.4.3	This amendment eliminates an inadvertent reference to the term *Operating Procedure* in the description of the required timeframe for noticing proposed changes to a

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	business practice manual and removes a potential ambiguity concerning what notice period applies to the proposed business practice manual changes involving clarifications of existing business practice manual language, grammatical errors, and revisions with minor significance. Under tariff section 22.11.1(4) (a), these changes may be effective at any time after the comment period expires.
22.11.1.5	This amendment clarifies that a business practice manual proposed revision request may be considered at a monthly meeting before the written comment period has ended.
22.11.1.6	This amendment makes typographical changes to section 22.11.1.6.
24.14.3.2	This amendment corrects grammar and use of defined terms in section 24.14.3.2.
25.1(d), 25.1.2, 25.1.2.1, 25.1.2.2	These amendments clarify that the tariff provisions governing the application of the ISO's interconnection procedures once a generating unit's power sales arrangements with a participating transmission owner or on-site customer have terminated apply to all generating units and not to just qualifying facility generating units. These amendments also clarify that the owner of a generating unit must describe through supporting information any change to the total capability or electrical characteristics of the generating unit in order to allow the participating transmission owner and ISO to assess whether the owner must become an interconnection customer under the ISO's tariff.
26.5	This amendment clarifies the effect of the end of the transition period on the tariff provisions that currently determine the ISO's transmission access charges.
27.1.1	These amendments substitute the words *transmission facility Constraints* with the new defined term *Transmission Constraints*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.* These amendments also clarify applicable time periods for market processes and the use of energy bid curves in the calculation of locational marginal prices. These amendments further clarify that the HASP, which is conducted hourly, calculates fifteen-minute HASP intertie locational marginal prices for the subsequent trading hour for non-dynamic system resources and exports.
27.1.1.3	This amendment substitutes the defined term *Constraints* with the new defined term *Transmission Constraints*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.* This amendment also makes typographical changes to this section.
27.1.2.1	This amendment deletes the use of the phrase *procurement requirement Constraints* in the description of how the ISO calculates ancillary service marginal prices and also

Section or Appendix	**Reason**
	changes the inadvertent use of a defined term *Constraint(s)* to the word *constraint(s)* in three instances. In its section, the ISO intends to refer to the word *constraints* pursuant to the plain meaning of that word.
27.4.1	This amendment clarifies applicable time periods for market processes that use security constrained unit commitment and eliminates conflicting uses of defined term *Time Horizon*. This amendment replaces this language with references to the applicable market intervals for each process. This amendment also corrects a typographical error.
27.4.1.1	This amendment clarifies applicable time periods for market processes and eliminates the conflicting use of the defined term *Time Horizon*.
27.4.2	This amendment clarifies applicable time periods for market processes that use security constrained economic dispatch and eliminates conflicting uses of defined term *Time Horizon*. This amendment replaces this language with references to the applicable market intervals for each process. This amendment also changes the inadvertent use of the words *resource Constraints* to *resource constraints*. In this section, the ISO intends to refer to the word *constraints* pursuant to the plain meaning of that word when it is used with the word in the context of the words *resource constraint*s. This amendment also changes the use of the words *transmission Constraints* to the new defined term *Transmission Constraints*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.*
27.4.3	This amendment replaces the use of the words *transmission constraints* with the new defined term *Transmission Constraints*.
27.4.3.1	This amendment replaces the use of the words *transmission Constraint, transmission constraint and constrained transmission facility and constraint* with the new defined term *Transmission Constraint*. The definition for the term *Transmission Constraint* will be the same as the current definition of the term *Constraint.*
27.4.3.2	This amendment replaces the use of the words *transmission Constraint* and *Constraint* with the new defined term *Transmission Constraint*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.*
27.4.3.5	This amendment corrects the use of a defined term and changes the use of the words *transmission Constraint* to the new defined term *Transmission Constraint*. The definition for the term *Transmission Constraint* will be the same as the current definition of the term *Constraint.*

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27.4.3.6	This amendment makes a typographical change to Section 27.4.3.6 and changes the use of the word *constraint* to the new defined term *Transmission Constraint*.
27.5.1	This amendment replaces the use of the words *transmission Constraints* with the new defined term *Transmission Constraints*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.*
27.5.1.1	This amendment replaces the use of the words *network Constraints* with the new defined term *Transmission Constraints*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.*
27.5.2	This amendment replaces the use of the words *network Constraints* with the new defined term *Transmission Constraints*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.*
27.5.3	This amendment replaces the use of the words *network Constraints* with the new defined term *Transmission Constraints*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.*
27.5.5	This amendment eliminates use of defined term *Time Horizon* and clarifies the use of load distribution factors in the ISO market processes.
27.5.6	This amendment replaces the use of the words *transmission Constraints* with the new defined term *Transmission Constraints*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.* This amendment also changes the defined term *Constraint* in subsection 27.5.6 (c) to the word *constraint* because the ISO intends to refer to the plain meaning of the word *constraint* in that subsection.
27.7.5	This amendment eliminates the use of the defined term *Time Horizon* and replaces it with a reference to the applicable real time unit commitment run as described in Section 34.2 of the ISO's tariff.
28.3.1	This amendment makes typographical changed to section 28.3.1.
30.5.2.1	This amendment clarifies the bid components of supply bids.
30.5.2.2	This amendment clarifies the bid components for supply bids on behalf of participating generators.
30.5.2.7, 30.5.3	These amendments reflect the fact that the ISO scheduling infrastructure and business rules system is now capable of generating residual unit commitment availability bids for resource adequacy capacity and interim capacity procurement

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	mechanism capacity. Accordingly, it is no longer necessary for scheduling coordinators to submit such bids. These amendments remove this obligation from the tariff.
30.5.3.1	This amendment makes a typographical change to reflect the use of a defined term.
30.7.3.1	This amendment clarifies that the ISO will not submit a spin or non-spin bid at $0 in the real-time market, if a resource submits an energy bid and only a spin or non-spin bid. This language is consistent with section 30.7.6.1.
30.7.6.1	This amendment clarifies the ancillary service bid extension rules to make them consistent with the ISO's scheduling infrastructure business rules. This amendment also clarifies a current business practice of the ISO concerning submission of regulation bids in the real time market for specified resources. Finally, this amendment clarifies that the ISO will not submit a spin or non-spin bid at $0 in the real-time market, if a resource submits and energy bid an only a spin or non-spin bid.
30.7.6.2, 30.7.6.2(c)	These amendments make typographical changes to sections 30.7.6.2 and 30.7.6.2(c) and replace the words *transmission constraints* with the new defined term *Transmission Constraints*.
31.1	This amendment clarifies the nature of bid submissions and the timeline for submission of bids in the ISO's day-ahead market.
31.2.1	This amendment replaces the use of the words *transmission Constraints* with the new defined term *Transmission Constraints*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.*
31.3.1.3	This amendment replaces the use of the words *transmission Constraint* with the new defined term *Transmission Constraint* and changes the use of the word *Constraint* with the new defined term *Transmission Constraint*. The definition for the term *Transmission Constraint* will be the same as the current definition of the term *Constraint.* This amendment also changes the inadvertent use of the defined term *Constraints* to the word *constraints* when the ISO intends to refer to the plain meaning of that word. Finally, this amendment makes typographical changes to this section and corrects the use of defined terms.
31.3	This amendment changes the inadvertent use of the defined term *Constraints* to the word *constraints* because the ISO intends to refer to the plain meaning of that word in this section. This amendment also makes a typographical change to section 31.3.
31.3.3	This amendment replaces the use of the words *Constraint(s)* with the new defined term *Transmission Constraint(s)* and changes the use of the word *Constraints* with the

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	new defined term *Transmission Constraints*. The definition for the term *Transmission Constraint* will be the same as the current definition of the term *Constraint.*
31.4, 31.4(d)	These amendments correct grammar and the use of defined terms and replace the replace the use of the words *transmission Constraint* with the new defined term *Transmission Constraint.* The definition for the term *Transmission Constraint* will be the same as the current definition of the term *Constraint.*
31.5.1.2	This amendment reflects the fact that the ISO scheduling infrastructure and business rules system is now capable of generating residual unit commitment availability bids for resource adequacy capacity and interim capacity procurement mechanism capacity. Accordingly, it is no longer necessary for scheduling coordinators to submit such bids. This amendment removes this obligation from the tariff.
31.5.4, 31.5.4(b)	These amendments change the inadvertent use of the words *resource Constraints* to *resource constraints*. In this section, the ISO intends to refer to the word *constraints* pursuant to the plain meaning of that word when it is used with the word in the context of the words *resource constraint*s. These amendments also change the use of the words *network Constraints* to the new defined term *Transmission Constraints*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.* This amendment also makes a conforming typographical change to Section 31.5.4.
31.5.5	This amendment changes the inadvertent use of the word *Constraints* to *constraints*. In this section, the ISO intends to refer to the word *constraints* pursuant to the plain meaning of that word.
31.6.4	This amendment deletes this section in its entirety because the provisions of this section have been displaced by resource adequacy provisions in Section 40.
31.7	This amendment corrects grammar and the use of defined terms.
33.2	This amendment eliminates the use of defined term *Time Horizon* and clarifies that the time period within which the HASP may commit resources with start-up times within the immediately following Trading Hour.
33.3	This amendment makes a typographical change to section 33.3.
33.8.1	This amendment eliminates the use of the defined term *Time Horizon* and clarifies that the commitment period for a constrained output generator is the time period immediately following the Trading Hour in which a specific HASP run is conducted.

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34, 34.2, 34.2.1, 34.3.1	These amendments make typographical changes to these sections. The amendments also eliminate the use of the defined term *Time Horizon* in those sections. The amendments clarify the commitment periods in the real-time market, real time unit commitment and real-time economic dispatch.
34.3.3	This amendment replaces the use of the words *network Constraint* with the new defined term *Transmission Constraint.* The definition for the term *Transmission Constraint* will be the same as the current definition of the term *Constraint.*
34.4	This amendment eliminates use of the defined term *Time Horizon* and describes the applicable time period for Short-Term Unit Commitment runs. This amendment specifies that the look-ahead period for the STUC process is at least three hours beyond the Trading Hour for which the real time unit commitment optimization was run, and that STUC will de-commit resources to the extent the physical characteristics of the resources allow them to be cycled in the look-ahead period. This amendment also clarifies that STUC does not produce locational marginal prices for settlement.
34.5 (2), (6), (7), (8), (9) and (12)	These amendments replace the inadvertent use of the defined term *Constraint* with the word *constraint* because the ISO intends to refer to the plain meaning of that word in this section. These amendments also eliminate use of the defined term *Time Horizon* and insert references to the forward-looking time period for each applicable market process.
34.7	This amendment makes a typographical change to section 34.7 to reflect use of a defined term.
34.9.1	This amendment makes a typographical change to section 34.9.1 to reflect use of a defined term. .
34.9.2	This amendment clarifies that exceptional dispatch authority applies generally to periodic testing of resource, including Pmax testing.
34.15.1	This amendment replaces the inadvertent use of the defined term *Constraint* with the word *constraint* because the ISO intends to refer to the plain meaning of that word in this section.
34.15.6 (a) , (b) and (c)	These amendments replace the inadvertent use of the defined term *Constraint* with the word *constraint* because the ISO intends to refer to the plain meaning of that word in this section.

Section or Appendix	**Reason**
34.16.3.4(a), (b), (c), (d), (e)	These amendments correct grammar and the use of defined terms. These amendments also provide a section cross-reference to the tariff section governing power factor requirements. .
34.17.2	This amendment corrects an inaccurate section cross-references in the tariff and adds a new cross-reference to section 34.11.2, which relates to the inability to execute dispatch instructions.
34.19.2.3	This amendment eliminates the use of the defined term *Time Horizon* and refers instead to the applicable time periods that comprise the real-time market for purposes of assessing when constrained output generators that can either be committed or shut-off are eligible to set the dispatch interval locational marginal price.
36.13.6	This amendment corrects an incorrect description of market clearing price.
36.15	This amendment deletes this section. The language in this section was necessary to transition from Financial Transmission Rights to Congestion Revenue Rights under a nodal market. The ISO has now transitioned to its nodal market. Therefore, the requirements in this section are no longer applicable because the events indentified in this section have either occurred or will no longer occur.
37.2.1.1	This amendment clarifies what type of instruction must be issued by the ISO and violated by a scheduling coordinator in order for the scheduling coordinator to be penalized under Section 37.2.
37.2.5	This amendment makes a typographical change to Section 37.2.5.
37.4.1.1	This amendment corrects a tariff section cross-reference. .
37.4.3.1	This amendment corrects a tariff section cross-reference.
37.5.2.1	This amendment reflects payment acceleration settlement timelines as approved by the Commission. (See, *California Independent System Operator Corp.*, 128 FERC ¶ 61,265 (2009).)
37.8.10	This amendment corrects an outdated term related to settlements, clarifies a section-cross reference, and corrects the use of a defined term.
37.9.3.1	This amendment corrects outdated terms related to settlements and reflects payment acceleration settlement timelines as approved by the Commission. (See, *California Independent System Operator Corp.*, 128 FERC ¶ 61,265 (2009).) This amendment also makes a typographical change to Section 37.9.3.1.

Section or Appendix	Reason
37.11.1	This amendment corrects typographical errors in section 37.11.1 and clarifies the application of penalties resulting from the inaccurate calculation of meter data. This amendment also reflects payment acceleration settlement timelines as approved by the Commission. (See, *California Independent System Operator Corp.*, 128 FERC ¶ 61,265 (2009).)
39.3.1 (3)	This amendment replaces the use of the words *transmission Constraints* with the new defined term *Transmission Constraints*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.*
39.6.1.6.1	This amendment removes references to NYMEX because it was sold. This amendment also corrects a typographical error in this section.
39.7	This amendment corrects the use of defined terms. This amendment also replaces the use of the defined term *Constraints* and the use of the words *transmission Constraint* with the new defined term *Transmission Constraint*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.*
39.7.1	This amendment makes a typographical change to section 39.7 to reflect the use of a defined term. .
39.7.1.1.1	This amendment makes a typographical change to this section and also reflects the names of publications and timing of publications used to determine gas prices index and to publish a single gas price index each day while using the most recent published for each market application (i.e. the real-time market uses more recent gas price index than prior day-ahead market). This amendment clarifies that the ISO uses the most recent available gas price index if a gas price index is unavailable for any reason.
39.7.1.2	This amendment clarifies that price corrected prices are utilized to calculate the LMP option for default energy bids.
39.7.2.1, 39.7.2.2	These amendments replace the use of the words *transmission Constraint* with the new defined term *Transmission Constraints*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.*
39.10	This amendment replaces the use of the words *transmission Constraint* with the new defined term *Transmission Constraints*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.* These amendments also modify the words *environmental Constraints* to read *environmental constraints* because the ISO intends to refer to the plain meaning of the word *constraints* in this context.

Section or Appendix	**Reason**
40.3.1.2	This amendment corrects an inadvertent error in the table included in section 40.3.1.2.
40.5.1(1), 40.5.1(1)(iv), 40.5.1(3)	These amendments make typographical changes to these sections
40.5.2, 40.6.2, 40.6.4.1	These amendments make typographical corrections to these sections.
40.6.8	This amendment makes a typographical change to section 40.6.8 and specifies that the ISO may insert a bid in the real-time market required under Section 40 for a resource adequacy resource that is use-limited, if the resource submits an energy bid and fails to submit an ancillary service bid.
41.5.1	This amendment makes a typographical correction to section 41.5.1.
43.1.2.1	This amendment aligns the provisions of section 43.1.2.1 relating to the cure period to submit a revised annual resource adequacy plan with the resource adequacy program objectives.
43.7.1	This amendment makes a typographical change to section 43.7.1 to reflect the use of a defined term.
43.7.3	This amendment reflects the fact that the ISO scheduling infrastructure and business rules system is now capable of generating residual unit commitment availability bids for resource adequacy capacity and interim capacity procurement mechanism capacity. Accordingly, it is no longer necessary for scheduling coordinators to submit such bids. This amendment clarifies that the ISO will now optimize these availability bids using a $0 bid.
44	This amendment deletes this section in its entirety because tariff authority in this section only applied for the first 30 days of the new market.
Appendix A, Aggregated Participating Load.	This amendment makes a typographical correction to this definition.
Appendix A, All Constraints Run	This amendment replaces the use of the words *transmission Constraint* with the new defined term *Transmission Constraints* in this definition. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.*

Section or Appendix	Reason
Appendix A, Available Transfer Capacity	This amendment clarifies the intended meaning of this definition.
Appendix A, CAISO Audit Committee	This amendment corrects the use of grammar in this definition.
Appendix A, Competitive Constraints Run	These amendments modify the words *competitive Constraints* to read *competitive constraints* because the ISO intends to refer to the plain meaning of the word *constraints* in this context. These amendments also clarify the definition of Competitive Constraint Run to make the description consistent with Section 31.2.1, which specifies that only constraints pre-designated as competitive constraints are enforced.
Appendix A, Congestion	This amendment replaces the use of the word *Constraint* with the new defined term *Transmission Constraints* in this definition. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.*
Appendix A, Constraints	This amendment deletes the defined term *Constraints*. The ISO is proposing to add a new defined term *Transmission Constraints* to Appendix A. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.*
Appendix A, Curtailable Demand	This amendment eliminates unnecessary language in the definition of Curtailable Demand.
Appendix A, Day-Ahead Inter-SC Trade Period	This amendment removes redundant language from this definition.
Appendix A, Delivery Network Upgrades	This amendment replaces the use of the word *Constraint* with the new defined term *Transmission Constraint* in this definition. The definition for the term *Transmission Constraint* will be the same as the current definition of the term *Constraint.*
Appendix A, Estimated Aggregate Liability	This amendment deletes a reference to CRR Holder in this definition because the use of the words market Participant includes a CRR Holder.
Appendix A, E-Tag	This amendment corrects the use of a defined term.
Appendix A, Forward Scheduling Charge	This amendment makes a typographical correction to this definition.

Section or Appendix	**Reason**
Appendix A, Full Network Model	This amendment replaces the use of the words *transmission Constraints* with the new defined term *Transmission Constraints* in this definition. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.*
Appendix A, Gross Load	These amendments make typographical changes to this definition.
Appendix A, HASP AS Award	This amendment makes typographical changes to this definition.
Appendix A, Henry Hub	This amendment deletes references to the new York Mercantile Exchange (NYMEX) because it was sold.
Appendix A, Locational Marginal Price	This amendment replaces the use of the words *transmission facility Constraints* with the new defined term *Transmission Constraints* in this definition. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.*
Appendix A, LSE	This amendment makes a typographical change to this definition.
Appendix A, Market Participant	This amendment corrects a typographical error in this section.
Appendix A, Market Usage Charge	This amendment makes a typographical change to this definition.
Appendix A, Material Change in Financial Condition	These amendments make a typographical change to this definition and delete references to CRR Holder in this definition because the use of the defined term Market Participant in this definition includes a CRR Holder.
Appendix A, Net Procurement	This amendment makes grammatical corrections to this section.
Appendix A, Non-Dynamic System Resource	This amendment makes grammatical corrections to this section.
Appendix A, Non-priced Quantity	This amendment replaces the use of the words *transmission constraints* with the new defined term *Transmission Constraints* in this definition. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.*

Section or Appendix	**Reason**
Appendix A, Participating Generator	These amendments clarify the circumstances under which a generator with a small generating unit will be required to comply with ISO tariff requirements applicable to participating generators. This clarification is a companion to the revisions to Section 4.6.3.1 and both conform to the similar tariff revisions filed by the ISO in Docket No. ER10-1755. These amendments clarify the ISO's past practice of excluding very small generating units from participation in its markets and clarify that a qualifying facility participating generator may satisfy its requirement to enter into an agreement with the ISO by executing a qualifying facility participating generator agreement instead of the regular participating generator agreement.
Appendix A, Participating TO Service Territory	This amendment clarifies the defined term by including the acronym (PTO) as part of the defined term.
Appendix A, PTO Service Territory	This amendment eliminates duplicate definitions in the tariff.
Appendix A, Qualifying Facility	This amendment makes a typographical correction to this definition.
Appendix A, Reliability Services Costs	This amendment corrects a typographical error in this definition.
Appendix A, RUC Zone	This amendment corrects a typographical error in this definition.
Appendix A, Scheduling Coordinator ID Code	This amendment clarifies the definition of this defined term as it is used in the tariff.
Appendix A, Seasonal CRR Load Metric	This amendment makes the definition of Seasonal CRR Load Metric consistent with tariff section 36.8.2.1.
Appendix A, Security Constrained Unit Commitment	These amendments eliminate the use of the defined term *Time Horizon*. These amendments also replace the use of the words *transmission constraints* with the new defined term *Transmission Constraints* in this definition. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.*
Appendix A, Settlement Period	This amendment makes a typographical correction to this definition.

Section or Appendix	**Reason**
Appendix A, Settlement, Metering, and Client Relations Charge	This amendment corrects the use of a defined term in this definition.
Appendix A, Shadow Price	This amendment replaces the inadvertent use of the defined term *Constraint* with the word *constraint* because the ISO intends to refer to the plain meaning of the word *constraint* in this context.
Appendix A, Short –Term Unit Commitment	This amendment clarifies applicable time periods for market processes and eliminates conflicting uses of defined term *Time Horizon.*
Appendix A, Simultaneous Feasibility Test	This amendment replaces the use of the words *transmission system Constraints* with the new defined term *Transmission Constraints* in this definition. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.*
Appendix A, Spinning Reserve Obligations	This amendment makes the term consistent with its definition by making the word *obligation* singular
Appendix A, System Resource	This amendment corrects a typographical error in connection with the use of the defined term *Interchange Schedules*.
Appendix A, Time Horizon	This amendment deletes the defined term *Time Horizon* because it has the potential to create confusion as the applicable binding period or the forward-looking time period used by the ISO's market processes.
Appendix A, Tolerance Band	These amendments clarify grammar and correct typographical errors.
Appendix A, Total Transfer Capability	This amendment makes typographical changes.
Appendix A, Transmission Constraint	This amendment adds the defined term *Transmission Constraint*. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraint.* The ISO is proposing to eliminate the defined term *Constraint* as part of this filing. This approach will allow the ISO to use the term constraint throughout the tariff to refer to the plain meaning of that word.

Section or Appendix	Reason
Appendix A, Transmission Constraints Enforcement List	These amendments replace the use of the words *transmission Constraints* with the new defined term *Transmission Constraints* in this definition. The definition for the term *Transmission Constraints* will be the same as the current definition of the term *Constraints.* These amendments also change the inadvertent use of the word *Constraints* to the word *constraints* in those instances in which the ISO intends to refer to the plain meaning of that word. Finally, these amendments make a typographical change in connection with the defined term *Transmission Contingencies*.
Appendix A, Unaccounted For Energy	This amendment makes a typographical change to this definition.
Appendix A, Unsecured Credit Limit	These amendments make a typographical change to this definition and delete references to *CRR Holder* in this definition because the use of the words *Market Participant* includes a *CRR Holder*.
Appendix A, Voltage Limits	This amendment makes a typographical change to this definition.
Appendix A, WSCC Reliability Criteria	This amendment eliminates the defined term *WSCC Reliability Criteria* consistent with the ISO's proposal The ISO proposes to delete the provisions of tariff sections 4.6.5.2 and 4.6.5.3 pursuant to the letter dated September 29, 2010 by the WECC notifying the ISO of its intent to terminate its Reliability Management System agreement and associated reliability criteria agreement with the ISO.
Appendix B.4, Article IV, sections 4.3, 4.6.1	These amendments correct typographical errors.
Appendix B.6, Article I	This amendment corrects an inadvertent omission from the tariff.
Appendix B.8, Article III, sections 3.2, 3.4.1	This corrects an inaccurate section cross-reference.
Appendix B.8, Article III, section 3.6; Schedules 2, 5	This amendment removes a requirement to include confidential operational contact information in the ISO's *pro forma* agreements in order to reduce the possibility of accidental disclosure and reduce the need to file confidential information with Commission.
Appendix B.9, section 3.4	This amendment removes a requirement to include confidential operational contact information in the ISO's *pro forma* agreements in order to reduce the possibility of accidental disclosure and reduce the need to file confidential information with Commission.
Appendix B.9, section 11.4	This amendment clarifies a section cross-reference to the *pro forma* agreement.

Section or Appendix	**Reason**
Appendix B.9, Schedule 1	This amendment makes a typographical change to Appendix B.9.
Appendix B.9, Schedule 1	This amendment removes a requirement to include confidential operational contact information in the ISO's *pro forma* agreements in order to reduce the possibility of accidental disclosure and reduce the need to file confidential information with Commission.
Appendix B.10, Article III, section 3.4, 3.6.1	These amendments correct inaccurate tariff section cross-references.
Appendix B.10, Article III, section 3.8, Schedule 3	This amendment removes a requirement to include confidential operational contact information in the ISO's *pro forma* agreements in order to reduce the possibility of accidental disclosure and reduce the need to file confidential information with Commission.
Appendix B.10, Schedule 3	This amendment makes a typographical change to Appendix B.10
Appendix B.14 Article 4 Section 4.3	This amendment makes a typographical change to Appendix B.14
Appendix C, section B	This amendment makes a typographical change to Appendix C to reflect the use of a defined term.
Appendix C, Section C	These amendments replace the use of the word *Constraint* with the new defined term *Transmission Constraint*. The definition for the term *Transmission Constraint* will be the same as the current definition of the term *Constraint.*
Appendix C, Section G.1.1	This amendment replaces the use of the words *transmission Constraint* with the new defined term *Transmission Constraint*. The definition for the term *Transmission Constraint* will be the same as the current definition of the term *Constraint.*
Appendix E, Section 6	This amendment changes the inadvertent use of the word *Constraints* to the word *constraints* in those instances in which the ISO intends to refer to the plain meaning of that word.
Appendix F, Schedule 1 Part A	This amendment clarifies that the monthly settlements, metering, and client relations charge applies only to active SCIDs in a given month.
Appendix F, Schedule 1, Part F	This amendment eliminates an outdated provision of Appendix F. This rate schedule no longer applies because Pacific Gas and Electric Company no longer serves as Path 15 facilitator.

Section or Appendix	**Reason**
Appendix F, Schedule 3, sections 1.1(c), 2, 5.1, 5.2	These amendments clarify the effect of the end of the transition period on the tariff provisions that currently determine the ISO's transmission access charges.
Appendix F, Schedule 3, sections 5.2, 5.5	These amendments make typographical corrections to these sections of Schedule 3 of Appendix F by changing the acronym PTO to a subscript.
Appendix F, Schedule 3, section 5.6	This amendment makes a typographical correction to Section 5.6 of Schedule 3 of Appendix by placing specific text in subscript.
Appendix F, Schedule 3, section 5.9	This amendment clarifies the application of the TAC transition charge at the end of the transmission access charge transition period and also makes a typographical correction to Section 5.9 of Schedule 3 of Appendix F.
Appendix F, Schedule 3, section 7	This amendment clarifies the application of the TAC transition charge at the end of the transmission access charge transition period.
Appendix F, Schedule 3, section 8.2	This amendment conforms the tariff provisions of this section of Schedule 3 of Appendix F to the ISO's current practice in issuing settlements invoices.
Appendix F, Schedule 3, section 13.2	This amendment conforms the tariff provisions of this section of Schedule 3 of Appendix F to the ISO's current practice in issuing settlements invoices.
Appendix G, Article 1	This amendment corrects a typographical error in connection with the use of a defined term.
Appendix G, Article 1	This amendment makes a typographical change to the definition of *Forced Outage*.
Appendix G, Article 4, Section 4.1.(c)(i)(C), 4.6(iv), 4.9(a)(iii), and 5.1(a)	These amendments change the inadvertent use of the word *Constraints* to the word *constraints* because the ISO intends to refer to the plain meaning of that word in the context of the phrase *Ramping constraint*.
Appendix G, Article 5, section 5.2(b)	This amendment corrects a typographical error in connection with the use of a defined term.
Appendix G, Article 6, Section 6.1(b)(v)	This amendment changes the inadvertent use of the word *Constraints* to the word *constraints* because the ISO intends to refer to the plain meaning of that word in the context of the phrase *Ramping constraint*.

Section or Appendix	**Reason**
Appendix L, Sections L.1.1, L.1.3	These amendments replace the use of the word *Constraints* with the new defined term *Transmission Constraints*. The definition for the term *Transmission Constraint*s will be the same as the current definition of the term *Constraints.*
Appendix L, Section L.1.6	This amendment makes a typographical change to this definition to reflect use of a defined term.
Appendix L, Section L.1.7	This amendment makes a typographical change to this definition to reflect use of a defined term and also replaces the use of the words *transmission Constraints* with the new defined term *Transmission Constraints*. The definition for the term *Transmission Constraint*s will be the same as the current definition of the term *Constraints.*
Appendix L, Section L.2	This amendment replaces the use of the words *Constraint* and *Hourly transmission Constraints* with the new defined term *Transmission Constraint*. The definition for the term *Transmission Constraint* will be the same as the current definition of the term *Constraints.*
Appendix L, Section L.4	This amendment replaces the use of the word *Constraints* with the new defined term *Transmission Constraints*. The definition for the term *Transmission Constraint*s will be the same as the current definition of the term *Constraints.*
Appendix M	This amendment clarifies references to Commission proceedings.
Appendix O, section 9.4	This amendment makes a typographical change to Section 9.4 of Appendix O.
Appendix P, section 5.1.7	This amendment is necessary because the current version of Appendix P, Section 5.1.7 refers to a referral under Appendix P, Section 12. However, that section describes the procedures for a DMM referral to FERC, whereas Appendix P, Section 5.1.7 deals with the ISO's reporting obligation to FERC.
Appendix P, section 5.5	This amendment makes a typographical change.
Appendix P, section 5.5.1	This amendment makes a typographical change.
Appendix P, Section 5.5.3	This amendment replaces the use of the words *transmission Constraints* with the new defined term *Transmission Constraints*. The definition for the term *Transmission Constraint*s will be the same as the current definition of the term *Constraints.*

Section or Appendix	Reason
Appendix P, section 8.1.4, 8.5.1, 8.6, 11.1. 11.1.3, 11.2, 11.3, 11.4.7, 11.5, 12.1, 12.2, 12.3, 12.4.4, 12.5	These amendments make typographical changes to reflect the use of defined terms.
Appendix Q section 4.1 and 4.2	These amendments clarify the ISO's requirements and make the tariff consistent with actual practice.
Appendix U, section 11.3	This amendment clarifies the process for execution of a large generator interconnection agreement.
Appendix U, Appendix 3 - Interconnection Feasibility Study Agmt., section 5.0	This amendment makes a typographical change by adding dashes to paragraphs in this section.
Appendix V, TOC	This amendment corrects the table of contents numbering in this appendix and also makes a typographical correction. This amendment also conforms the table of contents to the proposed deletion of the text of Appendix G of the large generator interconnection agreement.
Appendix V, Article 1	This amendment corrects an inaccurate reference to the NERC in the large generator interconnection agreement.
Appendix V, Article 5, section 5.4	This amendment conforms to the proposed deletion of the text of Appendix G of the large generator interconnection agreement.
Appendix V, Article 9, section 9.1	This amendment clarifies that execution of the WECC Reliability Management System Agreement is no longer necessary.
Appendix V, Article 9, section 9.6.2.1; Article 30, section 30.11; signature block and list of appendices	This amendment conforms to the proposed deletion of the text of Appendix G of the large generator interconnection agreement.

Section or Appendix	Reason
Appendix V, Appendix G to LGIA	This amendment clarifies that execution of the WECC Reliability Management System Agreement is no longer necessary.
Appendix X, section 8.4	This amendment corrects the use of a defined term.
Appendix Y, Article 6, Section 6.3.2.1	This amendment replaces the use of the words *transmission Constraints* with the new defined term *Transmission Constraints*. The definition for the term *Transmission Constraint*s will be the same as the current definition of the term *Constraints.*
Appendix Z, TOC, Article 11	This amendment corrects an inaccurate reference in the large generator interconnection agreement and corrects errors in formatting.
Appendix Z, Article 1	This amendment corrects an inaccurate reference to the NERC in the large generator interconnection agreement.
Appendix Z, Article 5, section 5.16	This amendment corrects an inaccurate cross-reference in the large generator interconnection agreement.
Appendix BB, TOC	This amendment makes a typographical correction.
Appendix BB, TOC	This amendment conforms the table of contents to the proposed deletion of the text of Appendix G of the large generator interconnection agreement.
Appendix BB, Article 1	This amendment corrects an incorrect reference to the NERC in the large generator interconnection agreement.
Appendix BB, Article 5, section 5.4	This amendment conforms to the proposed deletion of the text of Appendix G of the large generator interconnection agreement.
Appendix BB, Article 9, section 9.1	This amendment clarifies that execution of the WECC Reliability Management System Agreement is no longer necessary.
Appendix BB, Article 9, section 9.6.2.1; Article 30, section 30.11; signature block and list of appendices	This amendment conforms to the proposed deletion of the text of Appendix G of the large generator interconnection agreement.
Appendix BB, Appendix G to LGIA	This amendment reflects that execution of the WECC Reliability Management System Agreement is no longer necessary.

Section or Appendix	Reason
Appendix CC, Articles 1 and 5	This amendment corrects an inaccurate reference to NERC in the ISO’s large generator interconnection agreement and corrects a cross-reference in the large generator interconnection agreement.

Attachment B – Clean Tariff

Tariff Clarifications Filing

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

December 30, 2010

1.3.2 Specific Rules Of Interpretation Subject To Context

(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 CAISO Tariff;

(c) references to any law shall be deemed references to such law as it may be amended, replaced or restated from time to time;

(d) any reference to a "person" includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization or other entity, in each case, whether or not having separate legal personality;

(e) any reference to a day, month, week or year is to a calendar day, month, week or year;

(f) if the provisions of a CAISO Protocol and a section of the CAISO Tariff conflict, the provisions of the CAISO Tariff will prevail to the extent of the inconsistency;

(g) a reference to this CAISO Tariff or to a given agreement, or instrument shall be a reference to this CAISO Tariff or to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made;

(h) if the provisions of this CAISO Tariff and those of an existing contract conflict, with respect to Outage coordination, the existing contract will prevail to the extent of the inconsistency;

(i) time references are references to prevailing Pacific time;

(j) the Operating Procedures or Business Practice Manuals referenced in this CAISO Tariff, as may be amended from time to time, shall be posted on the CAISO Website, except as provided in Section 22.11, and such references in this CAISO Tariff shall be to the Operating Procedures or Business Practice Manuals then posted on the CAISO Website;

(k) if the provisions of an Operating Procedure or a Business Practice Manual and this CAISO Tariff conflict, the CAISO Tariff will prevail to the extent of the inconsistency;

(l) any reference to a day or Trading Day, week, month or year is a reference to a calendar day, week, month or year except that a reference to a Business Day shall have the meaning set forth in Appendix A; and

(m) the captions and headings in this CAISO 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 CAISO Tariff.

* * *

4.3.1.2 With respect to its submission of Bids, including Self-Schedules, to the CAISO, a New Participating TO shall become a Scheduling Coordinator or obtain the services of a Scheduling Coordinator that has been certified in accordance with Section 4.5.1, 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 CAISO 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.

For the period between the effective date of this provision and ending December 31, 2010, the TAC Transition Date pursuant to Section 4.2 of Appendix F, Schedule 3, New Participating TOs that have joined the CAISO and turned over Operational Control of their facilities and Entitlements shall receive the IFM Congestion Credit in accordance with Section 11.2.1.5, which IFM Congestion Credit shall only be applicable to those facilities and Entitlements in existence on the effective date of the CAISO's initial assumption of Operational Control over the facilities and Entitlements of a New Participating TO.

* * *

4.5.1.3 Additional Scheduling Coordinator ID Code Registration

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

* * *

4.5.3.2.2 Submitting Interchange Schedules prepared in accordance with all NERC, WECC and CAISO requirements, including providing E-Tags for all applicable transactions pursuant to WECC practices;

* * *

4.5.3.7 [NOT USED]

* * *

4.6 Relationship Between CAISO And Generators Version

The CAISO shall not accept Bids for any Generating Unit interconnected to the electric grid within the CAISO Balancing Authority Area otherwise than through a Scheduling Coordinator. The CAISO shall further not be obligated to accept Bids from Scheduling Coordinators relating to Generation from any Generating Unit interconnected to the electric grid within the CAISO Balancing Authority Area unless the relevant Generator undertakes in writing, by entering into a Participating Generator Agreement, QF PGA, or Metered Subsystem Agreement with the CAISO, to comply with all applicable provisions of this CAISO Tariff as they may be amended from time to time, including, without limitation, the applicable provisions of this Section 4.6 and Section 7.7.

4.6.3.1 Exemption for Generating Units Less Than One (1) MW

A Generator with a Generating Unit directly connected to a UDC system will be exempt from compliance with this Section 4.6 and Section 10.1.3 in relation to that Generating Unit provided that (i) the rated capacity of the Generating Unit is less than one (1) MW, and (ii) the Generator does not use the Generating Unit to participate in the CAISO Markets. 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 CAISO Tariff. A Generating Unit with a rated capacity of less than 500 kW, unless the Generating Unit is participating in an aggregation agreement approved by the CAISO, is not eligible to participate in the CAISO Markets and the Generator is not a Participating Generator for that Generating Unit.

* * *

4.6.5 NERC and WECC Requirements Version

4.6.5.1 Participating Generator Performance Standard

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

4.6.5.2 [NOT USED]

4.6.5.3 [NOT USED]

* * *

4.10.1.5.1 Information Requirements

The Candidate CRR Holder applicant must submit with its application:

(a) the proposed date for commencement of the CRR Allocation, CRR Auction or Secondary Registration System in which the applicant intends to qualify to participate, which may not be less than sixty (60) days after the date the application was filed, unless waived by the CAISO;

(b) financial Security information as set forth in Section 12;

(c) proof of completion of CRR training or expected completion of CRR training;

(d) the prescribed non-refundable application fee; and

(e) identity of the applicant's Affiliates, as described in Section 39.9.

* * *

4.10.2.2 Failure to Promptly Report a Material Change

If a Candidate CRR Holder or CRR Holder fails to inform the CAISO of a material change in its information provided to the CAISO including a Material Change in Financial Condition, that may affect the Financial Security of the CAISO, the CAISO may suspend or terminate the Candidate CRR Holder or CRR Holder's rights under the CAISO Tariff in accordance with the terms of Sections 12 and 4.10.3.2, respectively. If the CAISO intends to terminate the Candidate CRR Holder's status, it shall file a notice of termination with FERC in accordance with the terms of the CRR Entity Agreement. Such termination shall be effective upon acceptance by FERC of a notice of termination in accordance with the terms of the CRR Entity Agreement.

* * *

6.5.1.1.1 Annually, the CAISO shall provide information that will include, but is not limited to, the following:

(a) CRR Full Network Model;

(b) Transmission Constraints and Transmission Interface definitions;

(c) Load Distribution Factors for each CRR Allocation and CRR Auction that is published prior to the CRR Allocation and CRR Auction; and

(d) Nominations and/or parameters to be used for modeling in each annual CRR Allocation and CRR Auction processes: Transmission Ownership Rights, Existing Contracts and Converted Rights expected usage, and Merchant Transmission CRRs.

6.5.1.1.2 Monthly, the CAISO shall provide information that will include, but is not limited to, the following:

(a) CRR Full Network Model;

(b) Transmission Constraints and Transmission Interface definitions;

(c) Load Distribution Factors for each CRR Allocation and CRR Auction that is published prior to the CRR Allocation or CRR Auction; and

(d) Nominations and/or parameters to be used for modeling in each monthly CRR Allocation and CRR Auction processes: Transmission Ownership Rights, Existing

Contracts and Converted Rights expected usage, and Merchant Transmission CRRs.

* * *

6.5.2.1 Communications Regarding the State of the CAISO Controlled Grid

The CAISO shall use OASIS to provide public information to Market Participants regarding the CAISO Controlled Grid or facilities that affect the CAISO Controlled Grid. Such information may include but is not limited to:

(a) Future planned Outages of transmission facilities;

(b) Operating Transfer Capability (OTC); and

(c) Available Transfer Capability (ATC) for WECC paths and Transmission Interfaces with external Balancing Authority Areas.

* * *

6.5.2.2.2 Day-Ahead Market Bid Submittal

Seven (7) days prior to any Trading Day, Scheduling Coordinators can begin submitting Bids for the DAM for that Trading Day.

* * *

6.5.3.2.1 Before 10:00 a.m. one (1) day before the Operating Day the CAISO will publish updated Outage information regarding the transmission system on OASIS. The updated Outage information will include planned and actual Outage events per Transmission Interface, including Outage description, Outage start time and end time, and rating of the curtailed line.

6.5.3.2.2 The results of the Day-Ahead Market will be published on OASIS by 1:00 p.m. and will include:

(a) Total Day-Ahead Schedules (MWh) for total Supply and Demand by TAC Area and for the entire CAISO Balancing Authority Area;

(b) Total Day-Ahead Schedules (MWh) of imports and exports by Transmission Interface;

(c) Total Day-Ahead AS Awards by AS Region and AS type;

(d) RUC Prices by PNode and APNodes, RUC Forecast Demand for each RUC Zone, hourly RUC Capacity from Generation, and hourly RUC Capacity from imports for each TAC Area and the entire CAISO Balancing Authority Area;

(e) Day-Ahead LMP for Energy for each PNode and APNode, including the Energy, MCC and MCL components;

(f) Day-Ahead ASMP by AS Region and AS type;

(g) Day-Ahead mitigation indicator;

(h) CAISO Forecast of CAISO Demand for each TAC Area and the entire CAISO Balancing Authority Area;

(i) Shadow Prices of binding Transmission Constraints and an indication of whether the Transmission Constraints were binding because of the base operating conditions or a Contingency, and if caused by a Contingency, the identity of the specific Contingency; and

(j) Total Day-Ahead system Marginal Losses in MWh and Marginal Cost of Losses for each Trading Hour of the next Trading Day.

* * *

6.5.3.3 Communications with Market Participants

After the results of the Day-Ahead Market are posted, the CAISO will provide to parties that have signed a Non-Disclosure Agreement in accordance with Section 6.5.3.3.1, the daily post-Day-Ahead Market Transmission Constraints Enforcement List, which consists of the list of Transmission Constraints, including Contingencies and Nomograms that are enforced and not enforced in that day's Day-Ahead Market. Subsequently and prior to the next Day-Ahead Market, the CAISO will provide to parties the pre-Day-Ahead Market Transmission Constraints Enforcement List, which consists of the daily list of information for the Transmission Constraints, including Contingencies and Nomograms, the CAISO plans to enforce or not enforce for the next day's Day-Ahead Market. To the extent that the CAISO does not make either of these two reports available on any given Operating Day, the CAISO will instead provide only the list of Transmission Constraints, including Contingencies and Nomograms, that were enforced or not enforced for the applicable Day-Ahead Market within the next thirty (30) days, after which the information will not be provided.

* * *

6.5.4.2.2 No later than forty (40) minutes before the Trading Hour, on an hourly basis, the CAISO will publish on OASIS the following:

(a) Total HASP Intertie Schedules for imports and exports by TAC Area and for the entire CAISO Balancing Authority Area;

(b) HASP Intertie LMPs by PNodes and APNodes;

(c) HASP advisory LMPs by PNode and APNode;

(d) HASP Shadow Prices of binding Transmission Constraints and an indication of whether the constraints were binding because of the base operating conditions or contingencies and if caused by a contingency, the identity of the specific contingency; and

(e) Total HASP system Marginal Losses in MWh for the next Operating Hour.

* * *

6.5.6.1.1 The following information shall be published on OASIS ninety (90) days following the applicable Trading Day, with the exclusion of the information that is specific to Scheduling Coordinators:

(a) AS market Bids;

(b) Energy market Bids; and

(c) RUC market Bids.

* * *

6.5.7 Monthly Report on Conforming Transmission Constraints

The CAISO will post on its website a monthly report or incorporate into a monthly report on the degree of adjustments to Transmission Constraints made pursuant to Section 27.5.6. To the extent that in any given month the CAISO does not post on its website such reports, the CAISO will provide the report in the subsequent month. If it is not reasonably feasible to provide such the monthly report two months after the applicable month of the report, the information for the missed month will not be provided.

* * *

7.3.3 NAESB Standards

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

- Coordinate Interchange (WEQ-004, Version 001, October 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 004-0.1 through 004-17.2, and 004-A through 004-D;
- Area Control Error (ACE) Equation Special Cases Standards (WEQ-005, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 005-0.1 through 005-3.1.3, and 005-A;
- Manual Time Error Correction (WEQ-006, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 006-0.1 through 006-12;
- Inadvertent Interchange Payback (WEQ-007, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 007-0.1 through 007-2, and 007-A;
- Gas/Electric Coordination (WEQ-011, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Standards 011-0.1 through 011-1.6;
- Public Key Infrastructure (PKI) (WEQ-012, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Recommended Standard, Certification, Scope, Commitment to Open Standards, and Standards 012-0.1 through 012-1.26.5; and
- Measurement and Verification of Wholesale Electricity Demand Response (WEQ-015, 2008 Annual Plan Item 5(a), March 16, 2009).

The CAISO has applied for a waiver of the following NAESB WEQ standards:

- Business Practices for Open Access Same-Time Information Systems (OASIS), Version 1.4 (WEQ-001, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Standards 001-0.2 through 001-0.8, 001-0.14 through 001-0.20, 001-2.0 through 001-9.6.2, 001-9.8 through 001-12.5.2, and 001-A and 001-B;
- Business Practices for Open Access Same-Time Information Systems (OASIS) Standards & Communication Protocols, Version 1.4 (WEQ-002, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Standards 002-0.1 through 002-5.10;
- Open Access Same-Time Information Systems (OASIS) Data Dictionary, Version 1.4 (WEQ-003, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Standard 003-0;
- Transmission Loading Relief – Eastern Interconnection (WEQ-008, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 008-0.1 through 008-3.11.2.8, and 008-A through 008-D; and
- Business Practices for Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.4 (WEQ-013, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Introduction and Standards 013-0.1 through 013-4.2.

* * *

7.7.8 Under Frequency Load Shedding (UFLS)

7.7.8.1 Each UDC's UDCOA with the CAISO and each MSS Agreement through which the MSS Operator undertakes to the CAISO to comply with the provisions of the CAISO Tariff shall describe the UFLS program for that UDC or for that MSS.

* * *

7.7.15.4 Reporting Requirements under Section 7.7.15

The CAISO shall include reports on actions taken pursuant to Section 7.7.15 in the Exceptional Dispatch report provided in Section 34.9.4 of the CAISO Tariff. The report shall detail the frequency and types of actions taken by the CAISO pursuant to this Section 7.7.15, as well as the nature of the specific Market Disruptions that caused the CAISO to take action and the CAISO rationale for taking such actions, or the Market Disruption that was successfully prevented or minimized by the CAISO as a result of taking action pursuant to its authority under Section 7.7.15. This informational filing shall also contain general information on the Bids removed pursuant to Section 7.7.15, which may include the megawatt quantity, point of interconnection, specification of the Day-Ahead versus Real-Time Bid, and Energy or Ancillary Services Bid, and the CAISO's rationale for removal; provided, however, that any Scheduling Coordinator-specific individual Bid information will be submitted on a confidential basis consistent with FERC's rules and regulations governing requests for confidential treatment of commercially sensitive information.

* * *

8.3.1 Procurement Of Ancillary Services

The CAISO shall operate a competitive Day-Ahead Market, HASP, and Real-Time Markets to procure Ancillary Services. The Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) applications used in the Integrated Forward Market (IFM), HASP, and the Real-Time Market (RTM) shall calculate optimal resource commitment, Energy, and Ancillary Services Awards and Schedules at least cost to End-Use Customers consistent with maintaining System Reliability. Any Scheduling Coordinator representing Generating Units, System Units, Participating Loads, Proxy Demand Resources or imports of System Resources may submit Bids into the CAISO's Ancillary Services markets provided that it is in possession of a current certificate for the Generating Units, System Units, imports of System Resources, Participating Loads, or Proxy Demand Resources concerned. Regulation Up, Regulation Down, and Operating Reserves necessary to meet CAISO requirements not met by self-provision will be procured by the CAISO as described in this CAISO Tariff. The amount of Ancillary Services procured in the IFM is based on the CAISO Forecast of CAISO Demand and the forecasted intertie schedules in HASP for the Operating Hour net of (i) Self-Provided Ancillary Services from Generating Units internal to the CAISO Balancing Authority Area and Dynamic System

Resources certified to provide Ancillary Services and (ii) Ancillary Services self-provided pursuant to an ETC, TOR or Converted Right. The amount of additional Ancillary Services procured in the HASP is based on the CAISO Forecast of CAISO Demand, the Day-Ahead Schedules established net interchange, and the forecast of the intertie schedules for the Operating Hour in the HASP net of (i) available awarded Day-Ahead Ancillary Services, (ii) Self-Provided Ancillary Services from Generating Units internal to the CAISO Balancing Authority Area and Dynamic System Resources certified to provide Ancillary Services, and (iii) Ancillary Services self-provided pursuant to an ETC, TOR or Converted Right. The amount of Ancillary Services procured in the Real-Time Market is based upon the CAISO Forecast of CAISO Demand and the HASP Intertie Schedule established net interchange for the Operating Hour net of (i) available awarded Day-Ahead Ancillary Services, (ii) Self-Provided Ancillary Services from Generating Units internal to the CAISO Balancing Authority Area and Dynamic System Resources certified to provide Ancillary Services, (iii) additional Operating Reserves procured in HASP, and (iv) Ancillary Services self-provided pursuant to an ETC, TOR or Converted Right.

The CAISO will manage the Energy from both CAISO procured and Self-Provided Ancillary Services as part of the Real-Time Dispatch. In the Day-Ahead Market, the CAISO procures one-hundred percent (100%) of its Ancillary Service requirements based on the Day-Ahead Demand Forecast net of Self-Provided Ancillary Services. After the Day-Ahead Market, the CAISO procures additional Ancillary Services needed to meet system requirements from all resources, including imports from Non-Dynamic System Resources in the HASP, and Dynamic System Resources and Generation from internal resources in the Real-Time Market. The amount of Ancillary Services procured in the HASP and Real-Time Market is based on the CAISO Forecast of CAISO Demand for the Operating Hour net of Self-Provided Ancillary Services.

The CAISO procurement of Ancillary Services from Non-Dynamic System Resources in the HASP is for the entire next Operating Hour. The CAISO procurement of Ancillary Services from Dynamic System Resources and internal Generation in the Real-Time Market is for a fifteen (15) minute time period to which the relevant RTUC applies. The CAISO’s procurement of Ancillary Services from Non-Dynamic System Resources in HASP and from Dynamic System Resources and internal Generation in the Real-Time Market is based on the Ancillary Service Bids submitted or generated in the HASP consistent with the requirements in Section 30. The CAISO may also procure Ancillary Services pursuant to the requirements in Section 42.1 and as permitted under the terms and conditions of a Reliability Must-Run Contract.

The CAISO will contract for long-term Voltage Support service with owners of Reliability Must-Run Units under Reliability Must-Run Contracts. The CAISO will procure Black Start capability through individual contracts with Scheduling Coordinators for Reliability Must-Run Units and other Generating Units which have Black Start capability. These requirements and standards apply to all Ancillary Services whether self-provided or procured by the CAISO.

* * *

8.3.3.2 Criteria For Use of Ancillary Service Regions and Sub-Regions

The CAISO's use of an Ancillary Service Sub-Region occurs when the CAISO establishes a minimum or maximum limit for that Sub-Region. The CAISO's use of minimum and maximum procurement limits for Ancillary Services help to ensure that the Ancillary Services required in the CAISO Balancing Authority Area are dispersed appropriately throughout the CAISO Balancing Authority Area and accurately reflect the system topology and deliverability needs. The factors the CAISO will use in determining whether to establish or change minimum or maximum limits include, but are not limited to, the following: (a) the CAISO Forecast of CAISO Demand, (b) the location of Demand within the Balancing Authority Area, (c) information regarding network and resource operating constraints that affect the deliverability of Ancillary Services into or out of an Ancillary Service Region, (d) the locational mix of generating resources, (e) generating resource Outages, (f) historical patterns of transmission and generating resource availability, (g) regional transmission limitations and constraints, (h) transmission Outages, (i) Available Transfer Capability, (j) DA Schedules or HASP Intertie Schedules, (k) whether any Ancillary Services provided from System Resources requiring a NERC tag fail to have a NERC tag, and (l) other factors affecting System Reliability. Ancillary Services procured within a Sub-Region count toward satisfying the Ancillary Service requirements for the System Region or the Expanded System Region.

8.3.3.3 Notice to Market Participants

Pursuant to Section 6.5.2.3.3, the CAISO will publish forecasted Ancillary Service requirements, regional constraints, and the minimum and/or maximum Ancillary Service Regional Limits for the Ancillary Service Regions and any Sub-Regions by 6:00 p.m. on the day before the close of the Day-Ahead Market (two days prior to the Operating Day). After the completion of the Day-Ahead Market for a given Trading Day, the CAISO will publish the limits that were used in the IFM. If prior to the close of the HASP for a Trading Hour the CAISO makes a substantial change to a minimum and/or maximum limit for an Ancillary Service Region or Sub-Region, it will issue a Market Notice as soon as reasonably practicable after the occurrence of the circumstances that led to the change. After the close of the HASP for a Trading Hour, the CAISO will publish the limits that were used in the HASP and RTUC.

* * *

8.3.3.5 Base Market Model and Ancillary Services Procurement

The Base Market Model is used in the SCUC application, which optimizes the provision of Ancillary Services and Energy in order to meet Ancillary Service requirements and Energy requirements. The Base Market Model models Transmission Constraints as described in Section 27.5.1. The Ancillary Services Awards reflect the Ancillary Service Region and Sub-Region definitions and requirements. The Ancillary Service requirements, the definition of Ancillary Service Regions and Ancillary Service Sub-Regions, and any minimum or maximum limit that is used within an Ancillary Service Region or Ancillary Service Sub-Region are all inputs to the CAISO Markets Processes.

* * *

8.9.3.1 Compliance Testing of a Resources

The CAISO may test the Non-Spinning Reserve capability of a resource that is no Curtailable Demand by issuing unannounced Dispatch Instructions requiring the resource to come on line and ramp up or, in the case of a Proxy Demand Resource, to reduce Demand, 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 CAISO shall measure the response of the resource to determine compliance with its stated capabilities. For a Multi-

Stage Generating Resource the full range of Non-Spinning capacity is evaluated at the applicable MSG Configuration.

* * *

8.9.15.2 Penalties for Failure to Pass Performance Audit

The Scheduling Coordinator for a provider of RUC Capacity or an Ancillary Service whose resource fails a performance audit shall be subject to the financial penalties provided for in the CAISO Tariff, including those in Section 8.10. In addition, the sanctions described in Section 8.9.16 shall apply.

* * *

8.10.8.1 Rescission of Payments for Undispatchable Ancillary Service Capacity

The CAISO shall calculate the Real-Time ability of each Generating Unit, Participating Load, Proxy Demand Resource, System Unit or System Resource to deliver Energy from Ancillary Services capacity or Self-Provided Ancillary Services capacity for each Settlement Interval based on its maximum operating capability, actual telemetered output, and Operational Ramp Rate as described in Section 30.10. To make this determination for Multi-Stage Generating Resources the CAISO shall use the MSG-Configuration-specific Maximum Operating Limit and Operational Ramp Rate. System Resources that are awarded Ancillary Services are required to electronically tag (E-Tag as prescribed by the WECC) the Ancillary Services capacity. If the amounts of Ancillary Services capacity in an electronic tag differ from the amounts of Ancillary Services capacity for the System Resource, the Undispatchable Capacity will equal the amount of the difference, and will be settled in accordance with the provisions of Section 11.10.9.1.

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9.3.6.5.1 [NOT USED]

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9.3.10.6 With respect to Forced Outages of Generating Units that result in a reduction in maximum output capability that lasts fifteen (15) minutes or longer of 40 MW or more below the value registered in the Master File and ten (10) percent of the value registered in the Master File, the Operator shall provide to the CAISO an explanation of the Forced Outage and the estimated return time, within two (2) Business

Days after the Operator initially notifies the CAISO pursuant to Section 9.3.10.3.1 of the change in maximum output capability. The explanation shall include a description of the equipment failure or other cause and a description of all remedial actions taken by the Operator. Upon request of the CAISO, Operators, and where applicable, Eligible Customers, Scheduling Coordinators, UDCs and MSS Operators promptly shall provide information requested by the CAISO to enable the CAISO to review the changes made to the maximum output capability or to provide further information relative to the explanation of the Forced Outages submitted by the Operator and to prepare reports on Forced Outages. If the CAISO determines that any Forced Outage may have been the result of gaming or other questionable behavior by the Operator, the CAISO shall submit a report describing the basis for its determination to the FERC. The CAISO 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 Exceptional Dispatches; 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 CAISO 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 CAISO 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 CAISO an explanation of the Forced Outage within two (2) Business Days or failed to provide any additional information or access to the generating facility requested by the CAISO within a reasonable time.

* * *

9.5 Information About Outages

9.5.1 Approved Maintenance Outages

The CAISO and all Operators shall develop procedures to keep a record of Approved Maintenance Outages as they are implemented and to report the completion of Approved Maintenance Outages. Such records are available for inspection by Operators and Connected Entities at the CAISO 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 CAISO Outage Coordination Office, and such records will only be made available provided notice is given in writing to the CAISO fifteen (15) days in advance of the requested inspection date.9.5.2 Publication to Website

The CAISO shall publish on the CAISO Website a list of all Generating Units that have been reported to the CAISO pursuant to the CAISO Tariff or contract as undergoing Outages, together with the Generating Unit's PMax, the amount of the curtailment, the name of its Scheduling Coordinator, and other non-confidential information about these Generating Units as CAISO determines.

* * *

10.2.8.2.1 Local Access

If a CAISO Metered Entity desires to grant a third party local access to its revenue quality meters, those meters must be equipped with CAISO approved communications capabilities in accordance with the applicable Business Practice Manuals. The CAISO may set the password and any other security requirements for locally accessing the revenue quality meters of CAISO Metered Entities so as to ensure the security of those meters and their Revenue Quality Meter Data. The CAISO may alter the password and other requirements for locally accessing those meters from time to time as it determines necessary.

The CAISO must provide CAISO Metered Entities with the current password and other requirements for locally accessing their revenue quality meters. CAISO Metered Entities must not give a third party other than its Scheduling Coordinator local access to its revenue quality meters or disclose to that third party the password to its revenue quality meters without the CAISO's prior approval as set forth in a schedule to the Meter Service Agreement for CAISO Metered Entities which shall not unreasonably be withheld. CAISO Metered Entities will be responsible for ensuring that a third party approved by the CAISO to access its revenue quality meters only accesses the data it is approved to access and that the data are only accessed for the purposes for which the access was approved.

* * *

10.2.8.2.2 Remote Access

The CAISO may set the password and any other security requirements for remotely accessing the revenue quality meters of CAISO Metered Entities so as to ensure the security of those meters and their Revenue Quality Meter Data. The CAISO will alter the password and other requirements for remotely accessing those meters from time to time as it determines necessary. The CAISO must provide CAISO Metered Entities with the current password and other requirements for remotely accessing their revenue quality meters.

CAISO Metered Entities must not give a third party other than its Scheduling Coordinator remote access to its revenue quality meters or disclose to that third party the password to its revenue quality meters without the CAISO's prior approval as set forth in a schedule to the Meter Service Agreement for CAISO Metered Entities which shall not unreasonably be withheld. CAISO Metered Entities will be responsible for ensuring that a third party approved by the CAISO to access its revenue quality meters only accesses the data it is approved to access and that the data are only accessed for the purposes for which the access was approved.

* * *

10.3.6.2 Timing of Settlement Quality Meter Data Submission for Recalculation Settlement Statement T+38B

Scheduling Coordinators must submit Actual Settlement Quality Meter Data for the Scheduling Coordinator Metered Entities they represent to the CAISO no later than midnight on the forty-third (43) calendar day after the Trading Day (T+43C) for the Recalculation Settlement Statement T+38B. A Scheduling Coordinator that timely submits Actual Settlement Quality Meter Data for the Initial Settlement Statement T+7B pursuant to Section 10.3.6.1 may submit revised Actual Settlement Quality Meter Data for the Recalculation Settlement Statement T+38B no later than the forty-third (43) calendar day after the Trading Day pursuant to this Section.

(a) When Actual Settlement Quality Meter Data is not received by the CAISO for a Scheduling Coordinator Metered Entity by forty-three (43) calendar days after the Trading Day (T+43C), the Scheduling Coordinator has failed to submit complete and accurate meter data as required by Section 37.5.2.1 and will be subject to monetary penalty pursuant to Section 37.5.2.2.

(b) Any Scheduling Coordinator Estimated Settlement Quality Meter Data submitted by a Scheduling Coordinator on behalf of the Scheduling Coordinator Metered Entities it represents that is not replaced with Actual Settlement Quality Meter Data by forty-three (43) calendar days after the Trading Day (T+43C) has failed to submit complete and accurate meter data as required by Section 37.5.2.1 and will be subject to monetary penalty pursuant to Section 37.5.2.2. In the absence of Actual Settlement Quality Meter Data, Scheduling Coordinator Estimated Settlement Quality Meter Data will be used in the Recalculation Settlement Statements.

(c) The CAISO will not estimate a Scheduling Coordinator Metered Entity's Settlement Quality Meter Data for any outstanding metered Demand and/or Generation for use in a Recalculation Settlement Statement calculation. Any previous CAISO Estimated Settlement Quality Meter Data that the Scheduling Coordinator does not replace with Actual Settlement Quality Meter Data by forty-three (43) calendar days after the Trading Day (T+43C) will be set to zero. The CAISO will follow the control process described in the BPM for Metering to monitor and identify the CAISO Estimated Settlement Quality Meter Data that was not timely replaced and will take proactive measures to obtain the Actual Settlement Quality Meter Data. A Scheduling Coordinator that fails to replace CAISO Estimated Settlement Quality Meter Data with Actual Settlement Quality Meter Data by forty-three (43) calendar days after the Trading Day (T+43C) has failed to provide complete and accurate Settlement Quality Meter Data as required by Section 37.5.2.1 and will be subject to monetary penalty pursuant to Section 37.5.2.2.

10.3.6.3 Timing of Settlement Quality Meter Data Submission for Recalculation Settlement Statements after the Recalculation Settlement Statement T+38B

Scheduling Coordinators may continue to submit Actual Settlement Quality Meter Data for the Scheduling Coordinator Metered Entities they represent to the CAISO for use in Recalculation Settlement Statements subsequent to the Recalculation Settlement Statement T+38B according to timelines established in the CAISO Payments Calendar.

* * *

11.1.5 Settlement Quality Meter Data For Initial Statement T+7B

The CAISO's Initial Settlement Statement T+7B shall be based on the Settlement Quality Meter Data (actual or Scheduling Coordinator estimated) received in SQMDS. In the event Actual Settlement Quality Meter Data or Scheduling Coordinator Estimated Settlement Quality Meter Data is not received from a Scheduling Coordinator or CAISO Metered Entity, the CAISO will estimate Settlement Quality Meter Data for that outstanding metered Demand or Generation, excluding a Proxy Demand Resource, for the Initial Settlement Statement T+7B calculation.

(a) CAISO Estimated Settlement Quality Meter Data for metered Generation will be based on total Expected Energy and dispatch of that resource as calculated in the Real-Time Market and as modified by any applicable corrections to the Dispatch Operating Point for the resource.

(b) CAISO Estimated Settlement Quality Meter Data for metered Demand will be based on Scheduled Demand by the appropriate LAP. This value will be increased by fifteen (15) percent if the total actual system Demand in Real-Time, as determined by the CAISO each hour, is greater than the total estimated metered demand by more than fifteen (15) percent. Total estimated metered demand is the sum of the value of Scheduling Coordinator submitted metered Demand, CAISO polled estimated Settlement quality metered Demand, and Scheduled Demand for unsubmitted metered Demand at the fifth (5th) Business Day after the Trading Day (T+5B). CAISO Estimated Settlement Quantity Meter Demand for Participating Load will not be increased by fifteen (15) percent.

(c) CAISO will not estimate Settlement Quality Meter Data for Proxy Demand Resources.

* * *

11.2.4.5 CRR Balancing Account

The CRR Balancing Account shall accumulate: (1) the seasonal and monthly CRR Auction revenue amounts that were converted into daily CRRBA values as described in Section 11.2.4.3 and (2) any surplus revenue or shortfall generated from hourly CRR Settlements as described in Section 11.2.4.4. Interest accruing due to the CRR Balancing Account shall be at the CAISO's received interest rate and shall be credited to each monthly CRRBA Accrued Interest Fund, which is then allocated to monthly Measured Demand excluding Measured Demand associated with valid and balanced ETC, TOR, or Converted Rights Self-Schedule quantities for which IFM Congestion Credits and/or RTM Congestion Credits were provided in the same month.

11.2.5 Payment By OBAALSE For CRRs Through CRR Allocation Process

11.2.5.1 Pursuant to Section 36.9, in addition to other requirements specified therein, an OBAALSE will be eligible to participate in the CRR Allocation process if such entity has made a pre-payment to the CAISO and has met the requirements in Section 36.9. The prepayment amount shall equal the MW of CRR requested times the Wheeling Access Charge associated with the Scheduling Point corresponding to the CRR Sink times the number of hours in the period for each requested CRR MW amount. Except as provided in Section 36.9.2, such prepayment will be made three (3) Business Days in advance of the submission of CRR nominations for Monthly CRRs, Seasonal CRRs and Long Term CRRs to the CRR Allocation. Within thirty (30) days following the completion of the CRR Allocation process for Monthly CRRs, Seasonal CRRs and Long Term CRRs, the CAISO shall reimburse such OBAALSE the amount of money pre-paid for any CRRs that were not allocated to the entity.

* * *

11.5.1 Instructed Imbalance Energy Settlements

For each Settlement Interval, IIE consists of the following types of Energy: (1) Optimal Energy; (2) HASP Scheduled Energy; (3) Residual Imbalance Energy; (4) Real-Time Minimum Load Energy; (5) Exceptional Dispatch Energy; (6) Regulation Energy; (7) Standard Ramping Energy; (8) Ramping Energy Deviation; (9) Derate Energy; (10) Real-Time Self-Scheduled Energy; (11) MSS Load Following Energy; (12) Real-Time Pumping Energy; and (13) Operational Adjustments for the Day-Ahead and Real-Time. Payments and charges for IIE attributable to each resource in each Settlement Interval shall be settled by debiting or crediting, as appropriate, the specific Scheduling Coordinator's IIE Settlement Amount. The IIE

Settlement Amounts for the Standard Ramping Energy shall be zero. The IIE Settlement Amounts for Optimal Energy, Real-Time Minimum Load Energy, Regulation Energy, Ramping Energy Deviation, Derate Energy, Real-Time Pumping Energy, and Real-Time Self-Scheduled Energy shall be calculated as the product of the sum of all of these types of Energy and the Resource-Specific Settlement Interval LMP. For MSS Operators that have elected net Settlement, the IIE Settlement Amounts for Energy dispatched through the Real-Time Market optimization, Minimum Load Energy from System Units dispatched in Real-Time, Regulation Energy, Ramping Energy Deviation, Derate Energy, MSS Load Following Energy, Real-Time Pumping Energy, and Real-Time Self-Scheduled Energy shall be calculated as the product of the sum of all of these types of Energy and the Real-Time Settlement Interval MSS Price. For MSS Operators that have elected gross Settlement, regardless of whether that entity has elected to follow its Load or to participate in RUC, the IIE for such entities is settled similarly to non-MSS entities as provided in this Section 11.5.1. The remaining IIE Settlement Amounts are determined as follows: (1) IIE Settlement Amounts for the Energy from the HASP Intertie Schedules is settled per Section 11.4; (2) IIE Settlement Amounts for Residual Imbalance Energy are determined pursuant to Section 11.5.5.; and (3) IIE Settlement Amounts for Exceptional Dispatches are settled pursuant to Section 11.5.6.

* * *

11.5.1.1 Total IIE Settlement Amount

The total IIE Settlement Amount ($) per Settlement Interval for each Scheduling Coordinator is the sum of the IIE Settlement Amounts for the Standard Ramping Energy, MSS Load Following Energy, Optimal Energy, Real-Time Minimum Load Energy, HASP Scheduled Energy, Regulation, Ramping Energy Deviation, Derate Energy, Real-Time Self-Scheduled Energy, Residual Imbalance Energy, Exceptional Dispatch Energy, Real-Time Pumping Energy and Operational Adjustments for the Day-Ahead and Real-Time.

11.5.1.2 Total IIE Quantity

The total IIE quantity (MWh) per Settlement Interval for each Scheduling Coordinator is the sum of Standard Ramping Energy, MSS Load Following Energy, Optimal Energy, HASP Scheduled Energy, Real-Time Minimum Load Energy, Regulation Energy, Ramping Energy Deviation, Derate Energy, Real-

Time Self-Scheduled Energy, Residual Imbalance Energy, and Exceptional Dispatch Energy, Real-Time Pumping Energy, and Operational Adjustments for the Day-Ahead and Real-Time.

* * *

11.5.2 Uninstructed Imbalance Energy

Scheduling Coordinators shall be paid or charged a UIE Settlement Amount for each LAP, PNode or Scheduling Point for which the CAISO calculates a UIE quantity. UIE quantities are calculated for each resource that has a Day-Ahead Schedule, Dispatch Instruction, Real-Time Interchange Export Schedule or Metered Quantity. For MSS Operators electing gross Settlement, regardless of whether that entity has elected to follow its Load or to participate in RUC, the UIE for such entities is settled similarly to how UIE for non-MSS entities is settled as provided in this Section 11.5.2. The CAISO shall account for UIE in two categories: (1) Tier 1 UIE is accounted as the quantity deviation from the resource's IIE; and (2) Tier 2 UIE is accounted as the quantity deviation from the resource's Day-Ahead Schedule or as described in Section 11.2.5.4. For Generating Units, System Units of MSS Operators that have elected gross Settlement, Physical Scheduling Plants, System Resources and all Participating Load and Proxy Demand Resources, the Tier 1 UIE Settlement Amount is calculated for each Settlement Interval as the product of its Tier 1 UIE quantity and its Resource-Specific Tier 1 UIE Settlement Interval Price as calculated per Section 11.5.2.1, and the Tier 2 UIE Settlement Amount is calculated for each Settlement Interval as the product of its Tier 2 UIE quantity and the simple average of the relevant Dispatch Interval LMPs. The Tier 2 UIE Settlement Amount for non-Participating Load and MSS Demand under gross Settlement is settled as described in Section 11.5.2.2. For MSS Operators that have elected net Settlement, the Tier 1 UIE Settlement Amount is calculated for each Settlement Interval as the product of its Tier 1 UIE quantity and its Real-Time Settlement Interval MSS Price, and the Tier 2 UIE Settlement Amount is calculated for each Settlement Interval as the product of its Tier 2 UIE quantity and the Real-Time Settlement Interval MSS Price.

* * *

11.5.6.2.5.1 Allocation of Exceptional Dispatch Excess Cost Payments to PTOs

The total Excess Cost Payments calculated pursuant to Section 11.5.6.2.3 for the IIE from Exceptional Dispatches instructed as a result of a transmission-related modeling limitation in the FNM as described in

Section 34.9.3 in that Settlement Interval shall be charged to the Participating Transmission Owner in whose PTO Service Territory the transmission-related modeling limitation as described in Section 34.9.3 is located. If the modeling limitation affects more than one Participating TO, the Excess Cost Payments shall be allocated in proportion to the Transmission Revenue Requirements of the affected Participating TOs with PTO Service Territories. Costs allocated to Participating TOs under this section shall constitute Reliability Services Costs.

* * *

11.5.6.3.2 Allocation of Costs from Exceptional Dispatch Calls to Condition 2 RMR Units

(a) All costs associated with Energy provided by a Condition 2 RMR Unit operating other than according to a RMR Dispatch shall be allocated like other Instructed Imbalance Energy in accordance with Section 11.5.4.2.

(b) Start-Up Costs for Condition 2 RMR Units providing service outside the RMR Contract shall be treated similar to costs under Section 11.5.6.2.5.2.

11.5.6.4 Settlement of IIE from Exceptional Dispatches for Testing

The Exceptional Dispatch Settlement price for incremental IIE that is consumed or delivered as a result of an Exceptional Dispatch for purposes of Ancillary Services testing, periodic testing, including PMax testing, or pre-commercial operation testing for Generating Units is the maximum of the Resource-Specific Settlement Interval LMP or the Default Energy Bid price. All Energy costs for these types of Exceptional Dispatch will be included in the IIE Settlement Amount described in Section 11.5.1.1.

* * *

11.8.6.5.3 Allocation of the RUC Compensation Costs

(i) In the first tier, the RUC Compensation Costs are allocated to Scheduling Coordinators, based on their Net Negative CAISO Demand Deviation in that Trading Hour. The Scheduling Coordinator shall be charged at a rate which is the lower of (1) the RUC Compensation Costs divided by the Net Negative CAISO Demand Deviation for all Scheduling Coordinators in that Trading Hour; or (2) the RUC Compensation Costs divided by the RUC Award, for all

Scheduling Coordinators in that Trading Hour. Participating Load and Demand Response Providers shall not be subject to the first tier allocation of RUC Compensation Costs to the extent that the Participating Load's or Demand Response Provider's Net Negative CAISO Demand Deviation in that Trading Hour is incurred pursuant to a CAISO directive to consume in a Dispatch Instruction.

(ii) In the second tier, the Scheduling Coordinator shall be charged an amount equal to any remaining RUC Compensation Costs in proportion to the Scheduling Coordinator's metered CAISO Demand in any Trading Hour.

* * *

11.10.1.4 Voltage Support

The total payments for each Scheduling Coordinator for Voltage Support in any Settlement Period shall be the sum of the opportunity costs of limiting Energy output to enable reactive energy production in response to a CAISO instruction. The opportunity cost shall be calculated based on the product of the Energy amount that would have cleared the market at the price of the Resource-Specific Settlement Interval LMP minus the higher of the Energy Bid price or the Default Energy Bid price.

If applicable, Scheduling Coordinators shall also receive any payments under any long-term contracts due for the Settlement Period. Exceptional Dispatches for incremental or decremental Energy needed for Voltage Support procured through Exceptional Dispatch pursuant to Section 34.9.2 will be paid and settled in accordance with Sections 11.5.6. RMR Units providing Voltage Support are compensated in accordance with the RMR Contract rather than this Section 11.10.1.4.

* * *

11.10.3.2 Hourly Net Obligation for Spinning Reserves

Each Scheduling Coordinator's hourly net obligation for Spinning Reserves is determined as follows: the Scheduling Coordinator's total Ancillary Services Obligation for Operating Reserve for the hour multiplied by the ratio of the CAISO's total Ancillary Services Obligation for Spinning Reserves in the hour to the CAISO's total Operating Reserve Obligations in the hour (and if negative, multiplied by NOROCAF), reduced by the accepted Self-Provided Ancillary Services for Spinning Reserves, plus or minus any Spinning Reserve Obligations for the hour acquired or sold through Inter-SC Trades of Ancillary Services. The Scheduling Coordinator's total Operating Reserve Obligation for the hour is the sum of five (5) percent of its Real-Time Demand (except the Demand covered by firm purchases from outside the CAISO Balancing Authority Area) met by Generation from hydroelectric resources plus seven (7) percent of its Demand (except the Demand covered by firm purchases from outside the CAISO Balancing Authority Area) met by Generation from non-hydroelectric resources, plus one hundred (100) percent of any Interruptible Imports, which can only be submitted as a Self-Schedule in the Day-Ahead Market, plus its scheduled on-demand obligations.

* * *

11.10.9.4 Allocation of Rescinded Ancillary Services Capacity Payments

Payments rescinded pursuant to Sections 8.10.8 and 11.10.9 shall be allocated to Scheduling Coordinators in proportion to their Ancillary Services Obligation for the same Trading Day.

* * *

11.13.10 Confidentiality

The provisions of Sections 11.29.10.5 and 20.5 shall apply to this Section 11.13 between and among the RMR Owners, the CAISO and Responsible Utilities. Except as may otherwise be required by applicable law, all confidential information and data provided by RMR Owner or the CAISO to the Responsible Utility pursuant to the RMR Contract, Section 41.6 or this Section 11.13 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.

* * *

11.19.1.2 Annual Charges Assessment

Scheduling Coordinators shall pay FERC Annual Charges assessed against them by the CAISO on a monthly or annual basis. Scheduling Coordinators that pay FERC Annual Charges on a monthly basis shall make the payment for such charges within five (5) Business Days after issuance of the market Invoice or Payment Advice containing the charges. Scheduling Coordinators that must pay FERC Annual

Charges on an annual basis shall make the payment for such charges within five (5) Business Days from the Payment Date stated on the Invoice for FERC Annual Charges. For Scheduling Coordinators electing monthly settlement of the FERC Annual Charges, these charges are assessed for a given Trading Month in the same semi-monthly Invoice and Payment Advice containing the market Settlement and Grid Management Charge issued in accordance with the CAISO Payment Calendar. For Scheduling Coordinators electing yearly assessment of the FERC Annual Charges, the charges for a given Trading Month that are due annually are issued in accordance with the CAISO Payment Calendar on the same day as the market Invoice or Payment Advice but in a separate Invoice as indicated in Section 11.29.10. Further the FERC Annual Charges amounts are provided to Scheduling Coordinators at least twice a month in their Settlement Statements. Once the final FERC Annual Charge Recovery Rate is received from FERC in the spring or summer of the following year, revised FERC Annual Charges will be calculated and included on a supplemental Invoice or Payment Advice. All Scheduling Coordinators shall make payment for such charges within five (5) Business Days after the CAISO issues such supplemental Invoice.

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11.19.3.4 Under- or Over-Recovery of FERC Annual Charge Recovery Rate

If the FERC Annual Charges assessed by FERC against the CAISO for transactions on the CAISO Controlled Grid during any year exceed or fall short of funds collected by the CAISO for FERC Annual Charges with respect to that year by a range of ten (10) percent or less, the CAISO shall take such under- or over-recovery into account through an adjustment to the FERC Annual Charge Recovery Rate in accordance with this Section. Any deficiency of available funds necessary to pay for any assessment of FERC Annual Charges payable by the CAISO may be covered by an advance of funds from the CAISO's Grid Management Charge, provided any such advanced funds will be repaid. If the CAISO's collection of funds for FERC Annual Charges with respect to any year results in an under- or over-recovery of greater than ten (10) percent, the CAISO 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. The surcharge or credit shall be allocated among all active Scheduling Coordinators based on the percentage of the surcharge or credit that reflects the 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 CAISO in accordance with this CAISO Tariff at the time the CAISO issues a surcharge or credit under this section. The CAISO will issue any surcharges or credits under this section within sixty (60) days of receiving a FERC Annual Charge assessment from the FERC.

* * *

11.19.4 Credits And Debits Of FERC Annual Charges From SCs

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

* * *

11.20.5 Timely Payments

Scheduling Coordinators shall make timely payments to the CAISO pursuant to Preliminary NERC/WECC Charge Invoices within thirty (30) calendar days of issuance of such invoices. Scheduling Coordinators shall make timely payments to the CAISO pursuant to Final NERC/WECC Charge Invoices within fifteen (15) Business Days of issuance of such invoices.

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11.20.7.3 Disputes and Dispute-Related Corrections

Scheduling Coordinators shall be prohibited from disputing any Preliminary NERC/WECC Charge Invoice or Final NERC/WECC Charge Invoice, except on grounds that an error in a Preliminary NERC/WECC Charge Invoice or Final NERC/WECC Charge Invoice is due to a mere typographical or other ministerial error by the CAISO. A Scheduling Coordinator that wishes to dispute a NERC/WECC Charge Invoice on such grounds shall give the CAISO notice of dispute in writing within ten (10) calendar days of issuance. The notice of dispute shall state clearly the issue date of the Preliminary NERC/WECC Charge Invoice or Final NERC/WECC Charge Invoice, the item or calculation disputed, and the reasons for the dispute, and shall be accompanied by all available evidence reasonably required to support the claim. If the

Scheduling Coordinator is correct that the Preliminary NERC/WECC Charge Invoice or Final NERC/WECC Charge Invoice contains a typographical or other ministerial error and the resolution of the dispute makes correction necessary, the CAISO shall issue a corrected Preliminary NERC/WECC Charge Invoice or a corrected Final NERC/WECC Charge Invoice within fifteen (15) calendar days of issuance of the invoice that is being corrected.

Each Scheduling Coordinator that receives a Preliminary NERC/WECC Charge Invoice or a Final NERC/WECC Charge Invoice shall pay any net debit and shall be entitled to receive any net credit in a Preliminary NERC/WECC Charge Invoice or a Final NERC/WECC Charge Invoice on the Payment Date, regardless of whether there is any dispute regarding the amount of the debit or credit. The CAISO will issue corrected Preliminary NERC/WECC Charge Invoices or corrected Final NERC/WECC Charge Invoices if the resolution of a dispute concerning a Preliminary NERC/WECC Charge Invoice or a Final NERC/WECC Charge Invoice, brought pursuant to this Section 11.20, makes such a correction necessary.

* * *

11.21.1 CAISO Demand and Exports

If the CAISO corrects an LMP in the upward direction pursuant to Section 35 that impacts Demand in the Day-Ahead Market and the HASP such that either a portion of or the entire cleared CAISO Demand or export Economic Bid curve becomes uneconomic, then the CAISO will calculate and apply the Price Correction Derived LMP for settlement of CAISO Demand and exports in Section 11.2.1.2, 11.2.3, 11.2.1.4 and 11.4.1. The CAISO will calculate a Price Correction Derived LMP for each affected CAISO Demand and exports as follows: the total cleared MWhs of CAISO Demand or exports in the Day-Ahead Schedule or HASP Intertie Schedule, as applicable, multiplied by the corrected LMP, minus the make-whole payment amount, all of which is divided by the total cleared MWhs of CAISO Demand or export in the Day-Ahead Schedule or HASP Intertie Schedule, as applicable. The make-whole payment amount will be calculated on an hourly basis determined by the area between the Scheduling Coordinator's CAISO Demand or Export Bid curve and the corrected LMP, which is calculated as the MWhs for each of the cleared bid segments in the Day-Ahead Schedule or HASP Intertie Schedule for the affected resource, multiplied by the maximum of zero or the corrected LMP minus the bid segment price. For the purpose of this calculation, the CAISO will not factor in a make-whole payment amount for Self-Scheduled CAISO Demand or exports. Any non-zero amounts in revenue collected as a result of the application of the Price Correction Derived LMP will be captured through the calculation of the Congestion Charge reflected in Section 11.2.4.1 and the allocation of non-zero amounts of the sum of Imbalance Energy, Uninstructed Imbalance Energy, and Unaccounted for Energy in accordance with Section 11.5.4.

* * *

11.22.2.5.8 Settlements, Metering, and Client Relations Charge

The Settlements, Metering, and Client Relations Charge for each Scheduling Coordinator is fixed at $1000.00 per month, per Scheduling Coordinator ID Code with a non-zero invoice value where the non-zero value reflects market activity in the current Trading Month, as indicated in Appendix F, Schedule 1, Part A, subject to the requirements set out in Appendix F, Schedule 1, Part F. 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 in Appendix F, Schedule 1, Part E.

* * *

11.29.5.2 Right to Dispute

All Scheduling Coordinators, CRR Holders, Black Start Generators or Participating TOs shall have the right to dispute any item or calculation set forth in any Initial Settlement Statement T+7B, Recalculation Settlement Statement T+38B, or Incremental Changes in Recalculation Settlement Statements T+76B, T+18M, and T+35M in accordance with this CAISO Tariff, but not those set forth in Recalculation Settlement Statement T+36M.

* * *

11.29.7.1 Timing of the Settlements Process

The CAISO will publish: (i) Initial Settlement Statements T+7B on the seventh Business Day from the relevant Trading Day (T+7B), (ii) Recalculation Settlement Statements on the thirty-eighth Business Day from the relevant Trading Day (T+38B), (iii) Recalculation Settlement Statements on the seventy-sixth Business Day after the Trading Day (T+76B), (iv) Recalculation Settlement Statements on the Business Day eighteen (18) calendar months from the relevant Trading Day (T+18M) if necessary, (v)

Recalculation Settlement Statements on the Business Day thirty-five (35) calendar months from the relevant Trading Day (T+35M) if necessary, (vi) Recalculation Settlement Statements on the Business Day thirty-six (36) calendar months from the relevant Trading Day (T+36M) if necessary, and (v) any other Recalculation Settlement Statement authorized under Section 11.29.7.3. The CAISO will issue a notice to the market if a Recalculation Settlement Statement T+18M, Recalculation Settlement Statement T+35M, Recalculation Settlement Statement T+36M, or any additional Recalculation Settlement Statement is required for a Trading Day. The CAISO will notify affected Market Participants regarding failed or late publication of any settlement statements specified above and will rectify such failed or late publications pursuant to its procedure posted on the CAISO Website.

11.29.7.1.1 Initial Settlement Statement T+7B

The CAISO shall provide to each Scheduling Coordinator, CRR Holder, Black Start Generator or Participating TO for validation an Initial Settlement Statement T+7B for each Trading Day within seven (7) Business Days of the relevant Trading Day, covering all Settlement Periods in that Trading Day. Each Initial Settlement Statement T+7B will be produced using available Settlement Quality Meter Data (either actual or estimated) and CAISO Estimated Settlement Quality Meter Data. The Initial Settlement Statement T+7B will include the following:

(a) the amount payable or receivable by the Scheduling Coordinator, CRR Holder, Black Start Generator or Participating TO for each charge referred to in Section 11 for each Settlement Period in the relevant Trading Day;

(b) the total amount payable or receivable by that Scheduling Coordinator, CRR Holder, Black Start Generator or Participating TO for each charge for all Settlement Periods in that Trading Day after the amounts payable and the amounts receivable under (a) have been netted off pursuant to Section 11.29; and

(c) the components of each charge in each Settlement Period except for information contained in the Imbalance Energy report referred to in this Section 11.29.7.1.1; and

(d) a breakdown of the components of the Imbalance Energy charge (the Imbalance Energy report).

11.29.7.1.2 Recalculation Settlement Statements

The CAISO shall provide to each Scheduling Coordinator, CRR Holder, Black Start Generator or Participating TO Recalculation Settlement Statements in accordance with the CAISO Tariff and the CAISO Payments Calendar. Recalculation Settlement Statements shall be in a format similar to that of the Initial Settlement Statement T+7B and shall include the same granularity of information provided in the Initial Settlement Statement T+7B as amended following the validation procedure.

* * *

11.29.7.3 Additional Recalculation Settlement Statements

* * *

11.29.7.3.4 Recalculation Settlement Statements, post closing adjustments and the financial outcomes of CAISO ADR Procedures and any other dispute resolution may be invoiced separtely from monthly market activities in accordance with Section 11.29.10.3.

* * *

11.29.9.6.1 Clearing Account

(a) Subject to Section 11.29.3, and unless the CAISO instructs otherwise pursuant to Section 11.29.11, each CAISO Debtor shall remit to the CAISO Clearing Account the amount shown on the Invoice as payable by that CAISO Debtor for value not later than 10:00 a.m. on the Payment Date.

(b) On the Payment Date the CAISO shall be entitled to cause the transfer of such amounts held in a Scheduling Coordinator’s or CRR Holder’s CAISO prepayment account to the CAISO Clearing Account as provided in Section 11.29.3.

The CAISO shall calculate the amounts available for distribution to CAISO Creditors on the Payment Date and shall give irrevocable instructions to the CAISO Bank to remit from the CAISO Clearing Account to the relevant Settlement Accounts maintained by the CAISO Creditors, the aggregate amounts determined by the CAISO to be available for payment to CAISO Creditors for value by close of business on the

Payment Date if no CAISO Debtors are in default. If a CAISO Debtor is in default and until all defaulting amounts have been collected, the CAISO shall make payments as soon as practical within five (5) Business Days of the collection date posted in the CAISO Payments Calendar. If required, the CAISO shall instruct the CAISO Bank to transfer amounts from the CAISO Reserve Account to enable the CAISO Clearing Account to clear.

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

* * *

11.29.10.6 Payment of Estimated Statements and Invoices

When estimated Settlement Statements and Invoices or Payment Advices are issued by the CAISO, payments between the CAISO and Market Participants shall be made on an estimated basis and the necessary corrections shall be made by the CAISO as soon as practicable. The corrections will be reflected as soon as practicable in later Settlement Statements and Invoices and Payment Advices issued by the CAISO unless the CAISO has authorized the adjustment pursuant to Section 11.29.11. Failure to make such estimated payments shall result in the same consequences as a failure to make actual payments.

* * *

11.29.11 Instructions For Payment

Unless the CAISO instructs otherwise, each Scheduling Coordinator or CRR Holder shall remit to the CAISO Clearing Account the amount shown on the Invoice as payable by that Scheduling Coordinator or CRR Holder for value not later than 10:00 a.m. on the Payment Date. In the event of a verifiable error that would be reversed on a future Invoice, the CAISO may instruct a Scheduling Coordinator or CRR Holder not to remit payment for a specific charge shown on an Invoice. Any such occurrence will not constitute a payment default under the CAISO Tariff. If the payment amount would otherwise be payable to identified Market Participants, the CAISO will inform those entities that they will not be receiving payment for any specific corresponding charge code on a Payment Advice

* * *

11.31.1 Decline Monthly Charge – Imports

The Decline Monthly Charge – Imports shall be applied to each Scheduling Coordinator on the Settlement Statements issued for the last Trading Day of each Trading Month, and shall be the sum of the Scheduling Coordinator's Decline Potential Charges – Imports for each Settlement Period during that Trading Month multiplied by a ratio. The ratio will represent the portion of the Scheduling Coordinator's declined HASP Intertie Schedules for Energy imports that exceed the applicable exemption threshold during the Trading Month.

(a) The ratio will be calculated as follows:

(i) the Scheduling Coordinator's total MWh quantity of HASP Intertie Schedules for Energy imports that were not delivered during that Trading Month minus the applicable exemption threshold, divided by

(ii) the Scheduling Coordinator's total MWh quantity of HASP Intertie Schedules for Energy imports that were not delivered during the Trading Month.

(b) The applicable exemption threshold is the greater of the following:

(i) the Decline Threshold Quantity – Imports/Exports; or

(ii) the total MWh quantity of HASP Intertie Schedules for Energy imports during the Trading Month multiplied by the Scheduling Coordinator's Decline Threshold Percentage – Imports/Exports.

Notwithstanding the foregoing, the Decline Monthly Charge – Imports shall equal zero if either:

a) The percentage of the MWh quantity of HASP Intertie Schedules for Energy imports that the Scheduling Coordinator did not deliver during the Trading Month is less than the Decline Threshold Percentage – Imports/Exports; or

b) The total MWh quantity of HASP Intertie Schedules for Energy imports that the Scheduling Coordinator did not deliver in the applicable Trading Month is less than the Decline Threshold Quantity – Imports/Exports.

* * *

12.1.3.1.1 Calculation of the Estimated Aggregate Liability Amount

Except as described in Section 12.1.3.1.2, the CAISO shall use the method described in this Section 12.1.3.1.1 to calculate each Market Participant's Estimated Aggregate Liability. The Estimated Aggregate Liability represents the amount owed to the CAISO for all unpaid obligations, specifically, the obligations for the number of Trading Days outstanding at a given time based on the CAISO's Payments Calendar plus five (5) Trading Days based on the allowable period for Market Participants to respond to CAISO requests for additional Financial Security collateral (three (3) Business Days), and other liabilities including the value of a Market Participant's CRR portfolio, if negative. The charges the CAISO shall use to calculate Estimated Aggregate Liability shall be charges described or referenced in the CAISO Tariff. The CAISO shall calculate the Estimated Aggregate Liability for each Market Participant by aggregating the following obligations:

- invoiced amounts, i.e., any published but unpaid amounts on Invoices;
- published amounts, i.e., amounts for Trading Days for which Settlement Statements have been issued;
- estimated amounts, i.e., amounts based on estimated Settlement amounts calculated by the Settlement system using estimated meter data, and other available operational data;
- extrapolated amounts, i.e., amounts calculated for Trading Days for which neither actual nor estimated Settlement Statements have been issued;
- CRR portfolio value, i.e., the prospective value of the CRR portfolio, if negative, as described in Section 12.6.3;
- CRR Auction limit, i.e., the maximum credit limit for participation in a CRR Auction;

- CRR Auction awards (prior to invoicing), i.e., amounts to cover winning offers at the completion of the CRR Auction bur prior to invoicing;
- past-due amounts, i.e., any unpaid or past due amounts on Invoices;
- FERC Annual FERC Charges, i.e., FERC Annual Charges for a Market Participant that has elected to pay such amounts on an annual basis that are owed and outstanding and not already captured in any other component of Estimated Aggregate Liability;
- WAC Charges, i.e., WAC amounts for the current year or future years as specified in Section 36.9.2;
- Estimated Aggregate Liability adjustments, i.e., adjustments that may be necessary as a result of analysis performed as a result of Section 12.4.2; and
- extraordinary adjustments, i.e., adjustments to Settlement amounts related to FERC proceedings, if known and estimated by the CAISO, as described in Section 12.1.3.1.3.

For a Market Participant that maintains multiple BAID numbers, the Estimated Aggregate Liability of the Market Participant as a legal entity shall be calculated by summing the Estimated Aggregate Liabilities for all such BAID numbers and comparing the sum of the Estimated Aggregate Liabilities to the Aggregate Credit Limit of the Market Participant. Market Participants may recommend changes to the liability estimates produced by the CAISO's Estimated Aggregate Liability calculation through the dispute procedures described in Section 12.4.2.

* * *

12.5.1 Enforcement Actions Re Under-Secured Market Participants

If a Market Participant's Estimated Aggregate Liability, as calculated by the CAISO, at any time exceeds its Aggregate Credit Limit, the CAISO may take any or all of the following actions:

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

(b) The CAISO may limit trading, which may include rejection of Bids, including Self-Schedules, rejection or cancellation of Inter-SC Trades in their entirety (i.e., both sides of the Inter-SC Trade) at any time, and/or limiting other CAISO Market activity, including limiting eligibility to participate in a CRR Allocation or CRR Auction. In such case, the CAISO shall notify the Market Participant of its action and the Market Participant shall not be entitled to participate in the CAISO Markets or CRR Auctions or submit further Bids, including Self-Schedules, or otherwise participate in the CAISO Markets until the Market Participant posts an additional Financial Security Amount that is sufficient to ensure that the Market Participant's Aggregate Credit Limit is at least equal to its Estimated Aggregate Liability.

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

(d) The CAISO may restrict, suspend, or terminate the Market Participant's CRR Entity Agreement or any other service agreement.

(e) The CAISO may resell the CRR Holder's CRRs in whole or in part, including any Long Term CRRs, in a subsequent CRR Auction or bilateral transaction, as appropriate.

(f) The CAISO will not implement the transfer of a CRR if the transferee or transferor has an Estimated Aggregate Liability in excess of its Aggregate Credit Limit.

In addition, the CAISO may restrict or suspend a Market Participant's right to submit further Bids, including Self-Schedules, or require the Market Participant to increase its Financial Security Amount if at any time such Market Participant's potential additional liability for Imbalance Energy and other CAISO charges is determined by the CAISO to be excessive by comparison with the likely cost of the amount of Energy reflected in Bids or Self-Schedules submitted by the Market Participant.

* * *

13.5.2 Timing Of Adjustments

Upon determination that an award is payable by or to the CAISO pursuant to good faith negotiations or the CAISO ADR Procedures, the CAISO 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 Initial Settlement Statement T+7B or, in the case of an amount payable by the CAISO to a party, as soon as the CAISO and that party may agree.

* * *

14.5.2 Exclusion Of Certain Types Of Loss

The CAISO 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 the gross negligence or intentional wrongdoing on the part of the CAISO.

19. [NOT USED]

19.1 [NOT USED]

19.1.1 [NOT USED]

19.1.2 [NOT USED]

19.1.3 [NOT USED]

* * *

20.4 Disclosure

Notwithstanding anything in this Section 20 to the contrary,

* * *

(e) Notwithstanding the provisions of Section 20.2(f), information submitted through the Transmission Planning Process shall be disclosed as follows:

(i) Critical Energy Infrastructure Information may be provided to a requestor where such person is employed or designated to receive CEII by: (a) a Market Participant; (b) an electric utility regulatory agency within California; (c) an Interconnection Customer that has submitted an Interconnection Request to the CAISO under the CAISO's Large

Generator Interconnection Procedure or Small Generator Interconnection Procedure (LGIP or SGIP); (d) a developer having a pending or potential proposal for development of a Generating Facility or transmission addition, upgrade or facility and that is performing studies in contemplation of filing an Interconnection Request or submitting a transmission infrastructure project through the CAISO Transmission Planning Process; or (e) a not-for-profit organization representing consumer regulatory or environmental interests before a Local Regulatory Authority or federal regulatory agency. To obtain Critical Energy Infrastructure Information, the requestor must submit a statement as to the need for the CEII, and must execute and return to the CAISO the form of the non-disclosure agreement and non-disclosure statement included as part of the Business Practice Manual. The CAISO may, at its sole discretion, reject a request for CEII and upon such rejection, the requestor will be directed to utilize the FERC procedures for access to the requested CEII.

(ii) Information that is confidential under Section 20.2(f)(i) or 20.2.(f)(ii) may be disclosed to any individual designated by a Market Participant, electric utility regulatory agency within California, or other stakeholder that signs and returns to the CAISO the form of the non-disclosure agreement, nondisclosure statement and certification that the individual is a non-Market Participant, which is any person or entity not involved in a marketing, sales, or brokering function as market, sales, or brokering are defined in FERC's Standards of Conduct for Transmission Providers (18 C.F.R. § 358 et seq.), included as part of the Business Practice Manual; provided, however, that information obtained pursuant to this Section 20.4(e)(ii) will be provided only in composite form so that information related to individual Load Serving Entities or Scheduling Coordinators will not be disclosed.

(iii) Data base and other transmission planning information obtained from the WECC, or its successor, may be disclosed to individuals designated by a Market Participant, electric utility regulatory agency within California, or other stakeholder in accordance with the procedures set forth in the Business Practice Manual.

Nothing in this Section 20 shall limit the ability of the CAISO to aggregate data for public release about the adequacy of supply.

* * *

22.4.1 Effectiveness

Any notice, demand, or request in accordance with this CAISO Tariff, unless otherwise provided in this CAISO Tariff, 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, (d) upon receipt of confirmation by return e-mail if sent by e-mail, or (e) upon delivery if delivered by prepaid commercial courier service.

* * *

22.4.3 Notice Of Changes In Operating Procedures And BPMs

The CAISO will issue notice of any changes to any Operating Procedure or proposed changes to any Business Practice Manual. The effective date of any change or proposed change in any Business Practice Manual shall be established as part of the change management process set forth in Section 22.11 but will be no earlier than at least thirty (30) days from the date of publication of a Market Notice describing the change or proposed change, unless: (1) a different notice period is specified by state or federal law, (2) the change falls within Category A of Section 22.11.1.4(a) in which case the provisions of that section shall apply; (3) the change is reasonably required to address an emergency affecting the CAISO Controlled Grid or its operations, or (4) the change is to a provision of a Business Practice Manual that is necessitated by emergency circumstances specific to that Business Practice Manual. Such circumstances include, but are not limited to, any change necessary to ensure that the Business Practice Manual is consistent with the CAISO Tariff or any applicable law, regulation, NERC or WECC operating policies, guidelines and standards, or FERC order, in which case the CAISO shall give Market Participants as much notice as is reasonably practicable. Any notices issued under this provision shall be issued in accordance with the procedures set out in Section 22.11.

* * *

22.11.1.5 BPM PRR Review and Action

Any interested stakeholder or CAISO management may comment on a posted BPM PRR in accordance with the process set forth in the Business Practice Manual for BPM change management. To receive consideration, comments must be delivered electronically to the CAISO within ten (10) Business Days, or within any shorter period determined to be necessary or appropriate pursuant to the provisions of either Sections 22.11.1.7 or 22.11.1.8. Comments shall be posted to the CAISO Website and BPM PRRs shall be considered by the CAISO at a regularly established monthly public meeting or specially-noticed meeting dedicated to that purpose. Following any meeting to consider pending BPM PRRs and subject to the standards set forth in Section 22.11.1.4, the BPM change management coordinator shall issue a recommendation for action on each pending BPM PRR and shall publish for public comment a report on the recommendation in accordance with the procedures set forth in the Business Practice Manual for BPM change management. The report shall be sufficiently detailed and shall be published in a timeframe that allows interested stakeholders a meaningful opportunity to provide written comment. The BPM change management coordinator shall publish a final decision on any BPM PRR after considering stakeholder comments and all relevant impacts on their business needs and after the PRR recommendation report and comments concerning it have been discussed at a BPM change management meeting, in accordance with procedures set forth in the Business Practice Manual for BPM change management.

22.11.1.6 Right to Appeal to CAISO

Any entity eligible to submit a BPM PRR under Section 22.11.1.1 may, within ten (10) Business Days, appeal in writing the outcome of any BPM PRR to a committee comprising at least three CAISO executives established in accordance with procedures set forth in the Business Practice Manual for BPM change management. The CAISO will establish a standing meeting time for the BPM appeals committee to be used if needed and will establish the composition of the BPM appeals committee, including alternates in the case of schedule or other conflicts. Standing meeting dates and the BPM appeals committee composition will be established at least three months in advance. The CAISO may change the meeting time with ten (10) Business Days notice if required to accommodate schedules of the members of the BPM appeals committee. The executive sponsor of a BPM PRR may not sit in review of any appeal of a final decision regarding that same BPM PRR but may participate in and be present during the public discussion of any appeal. The CAISO committee will review the appeal and publish its decision to the appealing party and to the CAISO Website. If not satisfied with the decision on appeal, the appellant may raise concerns it may have with the CAISO Governing Board at the next regularly scheduled board meeting through the public comment period or through prior letter to the CAISO Governing Board.

* * *

24.14.3.2 FPL Energy, LLC

Pursuant to its Project Sponsor status, consistent with FERC's findings in Docket No. ER03-407, issued on June 15, 2006 (115 FERC ¶ 61, 329), FPL Energy, LLC shall receive Merchant CRRs associated with transmission usage rights modeled for the Blythe Path 59 upgrade, such Merchant CRRs to be in effect for a period of thirty (30) years, or the pre-specified intended life of the Merchant Transmission Facility, whichever is less, from the date Blythe Path 59 was energized. For the purpose of allocating Merchant

CRRs to FPL Energy, LLC over the Blythe Path 59 upgrade, the allocation of CRR Option in the import (east to west, from the Blythe Scheduling Point to the 230 kV side of the 161 kV to 230 kV transformer at the Eagle Mountain substation) as well as of CRR Option in the export (west to east) direction will be based on 57.1 percent of the total upgrade (96 MW out of the 168 MW), which is FPL Energy, LLC's share of the total upgrade as approved by FERC in the letter order issued by FERC on June 15, 2006 in Docket No. ER03-407 (115 FERC ¶ 61,329).

* * *

25.1 Applicability

This Section 25 and Appendix U (the Standard Large Generator Interconnection Procedures (LGIP)), Appendix Y (the Generator Interconnection Procedures (LGIP) for Interconnection Requests in a Queue Cluster Window), Appendix S (the Small Generator Interconnection Procedures (SGIP)), or Appendix W, as applicable, shall apply to:

(a) each new Generating Unit that seeks to interconnect to the CAISO Controlled Grid;

(b) each existing Generating Unit connected to the CAISO Controlled Grid that will be modified with a resulting increase in the total capability of the power plant;

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

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

25.1.2 Affidavit Requirement

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

25.1.2.1 If the CAISO and the applicable Participating TO confirm that the electrical characteristics are substantially unchanged, then that request will not be placed into the interconnection queue. However, the owner of the Generating Unit, or its designee, will be required to execute a Standard Large Generator Interconnection Agreement in accordance with Section 11 of Appendix U (the LGIP), a Large Generator Interconnection Agreement in accordance with Section 11 of Appendix Y (the GIP), a Small Generator Interconnection Agreement in accordance with Section 3.3.4, 3.4.5, or 3.5.7 and Section 4.8 of the SGIP, or an interconnection agreement in accordance with Appendix W, as applicable.

25.1.2.2 If the CAISO and the applicable Participating TO cannot confirm that the total capability and electrical characteristics are and will be substantially unchanged, then the owner of the Generating Unit, or its designee, shall be an Interconnection Customer required to submit an Interconnection Request and comply with Appendix U (the LGIP), Appendix Y (the GIP), Appendix S (the SGIP), or Appendix W, as applicable.

* * *

26.5 Transition Mechanism

During the ten-year TAC Transition Period described in Section 4 of Schedule 3 of Appendix F, the Original Participating TOs collectively shall pay to the CAISO 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 of Appendix F. Responsibility for such payments shall be allocated to Original Participating TOs in accordance with Schedule 3 of 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 CAISO 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. At the conclusion of the ten-year TAC Transition Period, the obligations of this Section 26.5 shall cease to apply.

* * *

27.1.1 Locational Marginal Prices For Energy

As further described in Appendix C, the LMP for Energy at any PNode is the marginal cost of serving the next increment of Demand at that PNode consistent with existing Transmission Constraints and the performance characteristics of resources, also considering, among other things, Energy Bid Curves. The LMP at any given PNode is comprised of three cost components: the System Marginal Energy Cost (SMEC); Marginal Cost of Losses (MCL); and Marginal Cost of Congestion (MCC). The IFM calculates LMPs for each Trading Hour of the next Trading Day. The HASP, which is conducted hourly for scheduling Non-Dynamic System Resources and exports for the subsequent Trading Hour, calculates fifteen-minute LMPs (HASP Intertie LMPs) for that Trading Hour. The simple average of the four fifteen-minute LMPs for the applicable Trading Hour computed at each Scheduling Point produces hourly LMPs for HASP Settlement of Energy at that Scheduling Point. The Real-Time Dispatch runs every five (5) minutes throughout each Trading Hour and calculates five-minute LMPs for the next Dispatch Interval. The CAISO uses the Resource-Specific Settlement Interval LMPs for Settlements of the Real-Time

Market. In the event that a Pricing Node becomes electrically disconnected from the market model during a CAISO Market run, the LMP, including the SMEC, MCC and MCL, at the closest electrically connected Pricing Node will be used as the LMP at the affected location.

* * *

27.1.1.3 Marginal Cost of Congestion

The Marginal Cost of Congestion at a PNode reflects a linear combination of the Shadow Prices of the binding Transmission Constraints in the network, multiplied by the corresponding Power Transfer Distribution Factor (PTDF). The Marginal Cost of Congestion may be positive or negative depending on whether a power injection (i.e., incremental Load increase) at that Location marginally increases or decreases Congestion.

* * *

27.1.2.1 Ancillary Service Marginal Prices – Sufficient Supply

As provided in Section 8.3, Ancillary Services are procured and awarded through the IFM, HASP and the Real-Time Market. The IFM calculates hourly Day-Ahead Ancillary Service Awards and establishes Ancillary Service Marginal Prices (ASMPs) for the accepted Regulation Up, Regulation Down, Spinning Reserve and Non-Spinning Reserve Bids. The IFM co-optimizes Energy and Ancillary Services subject to resource, network and regional constraints. In the HASP, the CAISO procures Ancillary Services from Non-Dynamic System Resources for the next Trading Hour as described in Section 33.7. The CAISO calculates the HASP settlement Ancillary Services price as described herein and further described in Section 33.8. In the Real-Time Market, the RTUC process that is performed every fifteen (15) minutes establishes fifteen (15) minute Ancillary Service Schedules, Awards, and prices for the upcoming quarter of the given Trading Hour. ASMPs are determined by first calculating Shadow Prices of Ancillary Services for each Ancillary Service type and the applicable Ancillary Services Regions. The Ancillary Services Shadow Prices are produced as a result of the co-optimization of Energy and Ancillary Services through the IFM, HASP, and the Real-Time Market, subject to resource, network, and requirement constraints. The Ancillary Services Shadow Prices represent the marginal cost of the relevant binding regional constraints at the optimal solution, or the reduction of the combined Energy and Ancillary Service procurement cost associated with a marginal relaxation of that constraint. If the constraint for an Ancillary Services Region is not binding, the corresponding Ancillary Services Shadow Price in the Ancillary Services Region is zero (0). During periods in which supply is sufficient, the ASMP for a particular Ancillary Service type and Ancillary Services Region is then the sum of the Ancillary Services Shadow Prices for the specific type of Ancillary Service and all the other types of Ancillary Services for which the subject Ancillary Service can substitute, as described in Section 8.2.3.5, for the given Ancillary Service Region and all the other Ancillary Service Regions that include that given Ancillary Service Region. During periods in which supply is insufficient, the ASMP for a particular Ancillary Service type and Ancillary Services Region will reflect the Scarcity Reserve Demand Curve Values set forth in Section 27.1.2.3.

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27.4.1 Security Constrained Unit Commitment

The CAISO uses SCUC to run the MPM-RRD processes associated with the DAM, the HASP, and the RTM. SCUC is conducted over multiple varying intervals to commit and schedule resources and to meet Demand for which Bids have been submitted and procure AS in the IFM, and to meet the CAISO Forecast of CAISO Demand in the MPM-RRD, RUC, HASP, STUC and RTUC. In the Day-Ahead MPM-RRD, IFM and RUC processes, the SCUC commits resources over the twenty-four (24) hourly intervals of the next Trading Day. In the RTUC, which runs every fifteen (15) minutes and commits resources for the RTM, the SCUC optimizes over a number of 15-minute intervals corresponding to the Trading Hours for which the Real-Time Markets have closed. The Trading Hours for which the Real-Time Markets have closed consist of (a) the Trading Hour in which the applicable run is conducted and (b) all the fifteen-minute intervals of the entire subsequent Trading Hour. In the HASP, which is a special run of the RTUC that runs once per hour, the SCUC schedules Non-Dynamic System Resources and exports for the applicable subsequent Trading Hour. In the STUC, which runs once an hour, the SCUC commits resources over the last fifteen (15) minutes of the imminent Trading Hour and the entire next four Trading Hours. The CAISO will commit Extremely Long Start Resources, for which commitment in the DAM does not provide sufficient time to Start-Up and be available to supply Energy during the next Trading Day as provided in Section 31.7.

27.4.1.1 Timing of Unit Commitment Instructions

For the applicable market intervals of any given CAISO Markets Process, the associated SCUC optimization will typically commit resources having different Start-Up Times, not all of which need to be started up immediately upon completion of that CAISO Markets Process. The CAISO may defer issuing a Start-Up Instruction to a resource that can be started at a later time and still be available to supply Energy at the time the CAISO Markets Process indicated it would be needed. The CAISO shall re-evaluate the need to commit such resources in a subsequent CAISO Markets Process based on the most recent forecasts and other information about system conditions.

27.4.2 Security Constrained Economic Dispatch

SCED is the optimization engine used to run the RTD to determine the optimal five-minute Dispatch Instructions throughout the Trading Hour consistent with resource constraints and Transmission Constraints within the CAISO Balancing Authority Area. In any given hour, the Real-Time Economic Dispatch of the Real-Time Market runs every five (5) minutes during which the SCED produces binding Dispatch Instructions for the immediately subsequent five-minute interval. For the applicable five-minute time period, through its SCED, the CAISO produces LMPs at each PNode that are used for Settlements as described in Section 11.5.

27.4.3 CAISO Markets Scheduling And Pricing Parameters

The SCUC and SCED optimization software for the CAISO Markets utilize a set of configurable scheduling and pricing parameters to enable the software to reach a feasible solution and set appropriate prices in instances where Effective Economic Bids are not sufficient to allow a feasible solution. The scheduling parameters specify the criteria for the software to adjust Non-priced Quantities when such adjustment is necessary to reach a feasible solution. The scheduling parameters are configured so that the SCUC and SCED software will utilize Effective Economic Bids as far as possible to reach a feasible solution, and will skip Ineffective Economic Bids and perform adjustments to Non-priced Quantities pursuant to the scheduling priorities for Self-Schedules specified in Sections 31.4 and 34.10. The scheduling parameters utilized for relaxation of internal Transmission Constraints are specified in Section 27.4.3.1. The pricing parameters specify the criteria for establishing market prices in instances where one or more Non-priced Quantities are adjusted by the Market Clearing software. The pricing parameters are specified in Sections 27.1.2.3, 27.4.3.2, 27.4.3.3 and 27.4.3.4. The complete set of scheduling and pricing parameters used in all CAISO Markets is maintained in the Business Practice Manuals.

27.4.3.1 Scheduling Parameters for Transmission Constraint Relaxation

The internal Transmission Constraint scheduling parameter is set to $5000 per MWh for the purpose of determining when the SCUC and SCED software in the IFM and RTM will relax an internal Transmission Constraint rather than adjust Supply or Demand bids or Non-priced Quantities as specified in Sections 31.3.1.3, 31.4 and 34.10 to relieve Congestion on the constrained facility. The effect of this scheduling parameter value is that if the optimization can re-dispatch resources to relieve Congestion on a Transmission Constraint at a cost of $5000 per MWh or less, the Market Clearing software will utilize such re-dispatch, but if the cost exceeds $5000 per MWh the market software will relax the Transmission Constraint. The corresponding scheduling parameter in RUC is set to $1250 per MWh.

27.4.3.2 Pricing Parameters for Transmission Constraint Relaxation

For the purpose of determining how the relaxation of a Transmission Constraint will affect the determination of prices in the IFM and RTM, the pricing parameter of the Transmission Constraint being relaxed is set to the maximum Energy Bid price specified in Section 39.6.1.1. The corresponding pricing parameter used in the RUC is set at the maximum RUC Availability Bid price specified in Section 39.6.1.2.

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27.4.3.5 Protection of TOR, ETC and Converted Rights Self-Schedules in the IFM

In accordance with the submitted and accepted TRTC Instructions, valid Day-Ahead TOR Self-Schedules, Day-Ahead ETC Self-Schedules and Day-Ahead Converted Rights Self-Schedules shall not be adjusted in the IFM in response to an insufficiency of Effective Economic Bids. The scheduling parameters associated with the TOR, ETC, or Converted Rights Self-Schedules will be set to values higher than the scheduling parameter associated with relaxation of an internal Transmission Constraint as specified in Section 27.4.3.1, so that when there is a congested Transmission Constraint that would otherwise subject a Supply or Demand resource submitted in a valid and balanced ETC, TOR or Converted Rights Self-Schedule to adjustment in the IFM, the IFM software will relax the Transmission Constraint rather than curtail the TOR, ETC, or Converted Rights Self-Schedule. This priority will be adhered to by the operation of the IFM Market Clearing software, and if necessary, by adjustment of Schedules after the IFM has been executed and the results have been reviewed by the CAISO operators.

27.4.3.6 Effectiveness Threshold

The CAISO Markets software includes a lower effectiveness threshold setting which governs whether the software will consider a bid "effective" for managing congestion on a congested Transmission Constraint. The CAISO will set this threshold at two (2) percent.

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27.5.1 Network Models used in CAISO Markets

The FNM is a representation of the WECC network model including the CAISO Balancing Authority Area that enables the CAISO to produce a Base Market Model that the CAISO then uses as the basis for formulating the individual market models used to conduct power flow analyses to manage Transmission Constraints for the optimization of each of the CAISO Markets.

27.5.1.1 Base Market Model used in the CAISO Markets

Based on the FNM the CAISO creates the Base Market Model (BMM), which is used as the basis for formulating, as described in section 27.5.6, the individual market models used in each of the CAISO Markets to establish, enforce, and manage the Transmission Constraints associated with network facilities. The Base Market Model is derived from the FNM by (1) introducing locations for modeling intertie schedules; and (2) introducing market resources that do not currently exist in the FNM due to their size and lack of visibility. In the Base Market Model, External Balancing Authority Areas and external transmission systems are modeled to the extent necessary to support the commercial requirements of the CAISO Markets. For those portions of the FNM that are external to the CAISO Balancing Authority Area, the Base Market Model may model the resistive component for accurate modeling of Transmission Losses, but accounts for losses in the external portions of the market model separately from Transmission Losses within the CAISO Balancing Authority Area. As a result the Marginal Cost of Losses in the LMPs is not affected by external losses. For portions of the Base Market Model that are external to the CAISO Balancing Authority Area, the CAISO Markets only enforce Transmission Constraints that reflect limitations of the transmission facilities and Entitlements turned over to the Operational Control of the CAISO by a Participating Transmission Owner, or that affect Congestion Management within the

CAISO Balancing Authority Area or on Interties. External connections are retained between Intertie branches within Transmission Interfaces. Certain external loops are modeled, which allows the CAISO to increase the accuracy of the Congestion Management process. Resources are modeled at the appropriate network Nodes.

The pricing Location (PNode) of a Generating Unit generally coincides with the Node where the relevant revenue quality meter is connected or corrected, to reflect the point at which the Generating Units are connected to the CAISO Controlled Grid. The Dispatch, Schedule, and LMP of a Generating Unit refers to a PNode, but the Energy injection is modeled in the Base Market Model for network analysis purposes at the corresponding Generating Unit's physical interconnection point), taking into account any losses in the non-CAISO Controlled Grid leading to the point where Energy is delivered to CAISO Controlled Grid.. Based on the BMM, the market models used in each of the CAISO markets incorporate physical characteristics needed for determining Transmission Losses and model Transmission Constraints within the CAISO Balancing Authority Area, which are then reflected in the Day-Ahead Schedules, AS Awards and RUC Awards, HASP Intertie Schedules, Dispatch Instructions and the LMPs resulting from each CAISO Markets Process. Further, in formulating the market models for the HASP, STUC, RTUC and the RTD processes, the Real-Time power flow parameters developed from the State Estimator are applied to the Base Market Model.

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27.5.2 Metered Subsystems

The FNM includes a full model of MSS transmission networks used for power flow calculations and Congestion Management in the CAISO Markets Processes. Transmission Constraints (i.e. circuit ratings, thermal ratings, etc.) within the MSS, or at its boundaries, that are modeled in the Base Market Model shall be monitored but not enforced in operation of the CAISO Markets. If overloads are observed in the forward markets, are internal to the MSS or at the MSS boundaries, and are attributable to MSS operations, the CAISO shall communicate such events to the Scheduling Coordinator for the MSS and coordinate any manual Re-dispatch required in Real-Time. If, independent of the CAISO, the Scheduling Coordinator for the MSS is unable to resolve Congestion internal to the MSS or at the MSS boundaries in Real-Time, the CAISO will use Exceptional Dispatch Instructions on resources that have been bid into the

HASP and RTM to resolve the Congestion. The costs of such Exceptional Dispatch will be allocated to the responsible MSS Operator. Consistent with Section 4.9, the CAISO and MSS Operator shall develop specific procedures for each MSS to determine how Transmission Constraints will be handled.

27.5.3 Integrated Balancing Authority Areas

To the extent sufficient data are available or adequate estimates can be made for an IBAA, the Base Market Model used by the CAISO for the CAISO Markets Processes will include a model of the IBAA's network topology. The CAISO monitors but does not enforce the Transmission Constraints for an IBAA in running the CAISO Markets Processes. Similarly, the CAISO models the resistive component for transmission losses on an IBAA but does not allow such losses to determine LMPs that apply for pricing transactions to and from an IBAA and the CAISO Balancing Authority Area, unless allowed under a Market Efficiency Enhancement Agreement. For Bids and Schedules between the CAISO Balancing Authority Area and the IBAA, the CAISO will model the associated sources and sinks that are external to the CAISO Balancing Authority Area using individual or aggregated injections and withdrawals at locations in the FNM that allow the impact of such injections and withdrawals on the CAISO Balancing Authority Area to be reflected in the CAISO Markets Processes as accurately as possible given the information available to the CAISO.

27.5.5 Load Distribution Factors

The CAISO will maintain a library of system-wide Load Distribution Factors for use in distributing Demand scheduled at the Default LAPs. The system Load Distribution Factors are derived from the State Estimator and are stored in the Load Distribution Factor library, and are updated periodically. For IFM the Load Distribution Factor library uses a similar-day methodology for smoothing the most recent Load Distribution Factors. The similar-day methodology uses data separately for each type of day. More recent days are weighted more heavily in the smoothing calculations. The market application then uses the set of Load Distribution Factors from the library that best represents the Load distribution conditions expected for use in the CAISO Market Processes. For the RTM, the State Estimator solution is used as a source for determining Load Distribution Factors. The Load Distribution Factor are also maintained for use for Demand scheduled at Custom LAPs. These custom Load Distribution Factors are not generated from the State Estimator and are fixed quantities representing the characteristics of the Custom LAP.

* * *

27.5.6 Management & Enforcement of Constraints in the CAISO Markets

The CAISO operates the CAISO Markets through the use of a market software system that utilizes various information including the Base Market Model, the State Estimator, submitted Bids including Self-Schedules, Generated Bids, and Transmission Constraints, including Nomograms and Contingencies transmission and generation Outages. The market model used in each of the CAISO Markets is derived from the most current Base Market Model available at that time. To create a more relevant time-specific network model for use in each of the CAISO Markets, the CAISO will adjust the Base Market Model to reflect Outages and derates that are known and applicable when the respective CAISO Market will operate, and to compensate for observed discrepancies between actual real-time power flows and flows calculated by the market software. Through this process the CAISO creates the market model to be used in each Day-Ahead Market, HASP, and each process of the Real-Time Market. The CAISO will manage the enforcement of Transmission Constraints, including Nomograms and Contingencies, consistent with good utility practice, to ensure, to the extent possible, that the market model used in each market accurately reflects all the factors that contribute to actual Real-Time flows on the CAISO Controlled Grid and that the CAISO Market results are better aligned with actual physical conditions on the CAISO Controlled Grid. In operating the CAISO Markets, the CAISO may take the following actions so that, to the extent possible, the CAISO Market solutions are feasible, accurate, and consistent with good utility practice:

(a) The ISO may enforce, not enforce, or adjust flow-based Transmission Constraints, including Nomograms and Contingencies, if the CAISO observes that the CAISO Markets produce or may produce results that are inconsistent with observed or reasonably anticipated conditions or infeasible market solutions either because (a) the CAISO reasonably anticipates that the CAISO Market run will identify Congestion that is unlikely to materialize in Real-Time even if the Transmission Constraint were to be ignored in all the markets leading to Real-Time, or (b) the CAISO reasonably anticipates that the CAISO Market will fail to identify Congestion that is likely to appear in the Real-Time. The ISO does not make such adjustments to intertie Scheduling Limits.

(b) The ISO may enforce or not enforce Transmission Constraints, including Nomograms and Contingencies, if the CAISO has determined that non-enforcement or enforcement, respectively, of such Constraints may result in the unnecessary pre-commitment and scheduling of use-limited resources.

(c) The CAISO may not enforce Transmission Constraints, including Nomograms and Contingencies, if it has determined it lacks sufficient visibility to conditions on transmission facilities necessary to reliably ascertain constraint flows required for a feasible, accurate and reliable market solution.

(d) For the duration of a planned or unplanned Outage, the CAISO may create and apply alternative Transmission Constraints, including Nomograms and Contingencies, that may add to or replace certain originally defined constraints.

(e) The CAISO may adjust Transmission Constraints, including Nomograms and Contingencies, for the purpose of setting prudent operating margins consistent with good utility practice to ensure reliable operation under anticipated conditions of unpredictable and uncontrollable flow volatility consistent with the requirements of Section 7.

To the extent that particular Transmission Constraints, including Nomograms and Contingencies, are not enforced in the operations of the CAISO Markets, the CAISO will operate the CAISO Controlled Grid and manage any Congestion based on available information including the State Estimator solutions and available telemetry to Dispatch resources through Exceptional Dispatch to ensure the CAISO is operating the CAISO Controlled Grid consistent with the requirements of Section 7.

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27.7.5 Constrained Output Generators In The Real-Time Market

A COG that can be started up and complete its Minimum Run Time within a five-hour period can be committed by the STUC. A COG that can be started up within the applicable RTUC run as described in Section 34.2 can be committed by the RTUC. The RTD will dispatch a COG up to its PMax or down to zero (0) to ensure a feasible Real-Time Dispatch. The COG is eligible to set the RTM LMP in any Dispatch Interval in which a portion of its output is needed to serve Demand, not taking into consideration its Minimum Run Time constraint. For the purpose of making this determination and setting the RTM LMP, the CAISO treats a COG as if it were flexible with an infinite Ramp Rate between zero (0) and its PMax, and uses the COG's Calculated Energy Bid. In any Dispatch Interval where none of the output of a COG is needed as a flexible resource to serve Demand, the CAISO shall not dispatch the unit. In circumstances in which the output of the COG is not needed as a flexible resource to serve Demand, but the unit nonetheless is online as a result of a previous commitment or Dispatch Instruction by the CAISO, the COG is eligible for Minimum Load Cost compensation.

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28.3.1 Information Requirements

An Inter-SC Trade of IFM Load Uplift Obligation shall contain the following information: (i) the Scheduling Coordinator ID Code for the Scheduling Coordinator from whom the MW amounts of IFM Load Uplift Obligation is traded; (ii) the Scheduling Coordinator ID Code for the Scheduling Coordinator to whom the MW amounts of IFM Load Uplift Obligation is traded; (iii) the applicable Location of the Inter-SC Trade of IFM Load Uplift Obligation; (iv) the time period over which the trade will take place, including the start-date and time and the end-date and time; and (v) the quantity (MW) of the IFM Load Uplift Obligation to be traded.

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30.5.2.1 Common Elements for Supply Bids

In addition to the resource-specific Bid requirements of this Section, all Supply Bids must contain the following components: Scheduling Coordinator ID Code; Resource Location or Resource ID, as appropriate; MSG Configuration ID, as applicable; PNode or Aggregated Pricing Node as applicable; Energy Bid Curve; Self-Schedule component; Ancillary Services Bid; RUC Availability Bid; as applicable, the Market to which the Bid applies; Trading Day to which the Bid applies; Priority Type (if any). Supply Bids offered in the CAISO Markets must be monotonically increasing. Energy Bids in the RTM must also contain a Bid for Ancillary Services to the extent the resource is certified and capable of providing Ancillary Service in the RTM up to the registered certified capacity for that Ancillary Service less any Day-Ahead Ancillary Services Awards.

Scheduling Coordinators must submit the applicable Supply Bid components, including Self-Schedules, for the submitted MSG Configuration.

30.5.2.2 Supply Bids for Participating Generators

In addition to the common elements listed in Section 30.5.2.1, Supply Bids for Participating Generators shall contain the following components as applicable: Start-Up Bid, Minimum Load Bid, Ramp Rate, Minimum and Maximum Operating Limits; Energy Limit, Regulatory Must-Take/Must-Run Generation; Contingency Flag; and Contract Reference Number (if any). Scheduling Coordinators submitting these Bid components for a Multi-Stage Generating Resource must do so for the submitted MSG Configuration. A Scheduling Coordinator for a Physical Scheduling Plant or a System Unit may include Generation Distribution Factors as part of its Supply Bid. If the Scheduling Coordinator has not submitted the Generation Distribution Factors applicable for the Bid, the CAISO will use default Generation Distribution Factors stored in the Master File. All Generation Distribution Factors used by the CAISO will be normalized based on Outage data that is available to the automated market systems. A Multi-Stage Generating Resource and its MSG Configurations are registered under a single Resource ID and Scheduling Coordinator for the Multi-Stage Generating Resource must submit all Bids for the resource's MSG Configurations under the same Resource ID. For a Multi-Stage Generating Resources Scheduling Coordinators may submit bid curves for up to ten individual MSG Configurations of their Multi-Stage Generating Resources into the Day-Ahead Market and up to three individual MSG Configurations into the Real-Time Market. Scheduling Coordinators for Multi-Stage Generating Resources must submit a single Operational Ramp Rate for each MSG Configuration for which it submits a supply Bid either in the Day-Ahead Market or Real-Time Market. For Multi-Stage Generating Resources the Scheduling Coordinator may submit the Transition Times, which cannot be greater than the maximum Transition Time registered in the Master File. To the extent the Scheduling Coordinator does not submit the Transition Time that is a registered feasible transition the CAISO will use the registered maximum Transition Time for that MSG Transition for the specific Multi-Stage Generating Resource.

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30.5.2.7 RUC Availability Bids

Scheduling Coordinators may submit RUC Availability Bids for specific Generating Units capacity that is not Resource Adequacy Capacity or ICPM Capacity of in the DAM. Scheduling Coordinators for Resource Adequacy Capacity or ICPM Capacity must participate in RUC to the extent that such capacity is not reflected in an IFM Schedule but need not submit RUC Availability Bids, Resource Adequacy Capacity participating in RUC will be optimized using a zero dollar ($0/MW-hour) RUC Availability Bid. For Multi-Stage Generating Resources the RUC Availability Bids shall be submitted at the MSG Configuration. Capacity that does not have Bids for Supply of Energy in the IFM will not be eligible to participate in the RUC process. The RUC Availability Bid component is MW-quantity of non-Resource Adequacy Capacity in $/MW per hour.

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30.5.3 Demand Bids

Each Scheduling Coordinator representing Demand, including Non-Participating Load and Aggregated Participating Load, shall submit Bids indicating the hourly quantity of Energy in MWh that it intends to purchase in the IFM for each Trading Hour of the Trading Day. Scheduling Coordinators must submit Demand Bids, including Self Schedules, for CAISO Demand at Load Aggregation Points except as provided in Section 30.5.3.2.

30.5.3.1 Demand Bids Components

Demand Bids must have the following components: Scheduling Coordinator ID Code; a Demand Bid curve that is a monotonically decreasing staircase function of no more than ten (10) segments defined by eleven (11) ordered pairs of MW and $/MWh; Location Code for the LAP, Custom LAP or PNode, as applicable; and hourly scheduled MWh within the range of the Bid curve, including any zero values, for each Settlement Period of the Trading Day.

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30.7.3.1 Validation Prior to Market Close and Master File Update

The CAISO conducts Bid validation in three steps as described below. For a Multi-Stage Generating Resource the validation described herein is done for each submitted MSG Configuration.

Step 1: The CAISO will validate all Bids after submission of the Bid for content validation which determines that the Bid adheres to the structural rules required of all Bids as further described in the Business Practices Manuals. If the Bid fails any of the content level rules the CAISO shall assign it a rejected status and the Scheduling Coordinator must correct and resubmit the Bid.

Step 2: After the Bids are successfully validated for content, but prior to the Market Close of the DAM, the Bids will continue through the second level of validation rules to verify that the Bid adheres to the applicable CAISO Market rules and if applicable, limits based on Master File data. If the Bid fails any level two validation rules, the CAISO shall assign the Bid as invalid and the Scheduling Coordinator must either correct or resubmit the Bid.

Step 3: If the Bid successfully passes validation in Step 2, it will continue through the third level of validation where the Bid will be analyzed based on its contents to identify any missing Bid components that must be either present for the Bid to be valid consistent with the market rules contained in Article III of this CAISO Tariff and as reflected in the Business Practice Manuals. At this stage the Bid will either be automatically modified for correctness and assigned a status of conditionally modified or modified, or if it can be accepted as is, the Bid will be assigned a status of conditionally valid, or valid. A Bid will be automatically modified and assigned a status of modified or conditionally modified Bid, whenever the CAISO inserts or modifies a Bid component. The CAISO will insert or modify a Bid component whenever (1) a Self-Schedule quantity is less than the lowest quantity specified as an Economic Bid for either an Energy Bid or Demand Bid, in which case the CAISO extends the Self-Schedule to cover the gap; (2) for non-Resource Adequacy Resources, the CAISO will extend the Energy Bid Curve using Proxy Costs to cover any capacity in a RUC Bid component, if necessary; and (3) for a Resource Adequacy Resource that is not a Use-Limited Resource, the CAISO will extend the Energy Bid Curve using Proxy Costs to cover any capacity in a RUC Bid component and, if necessary, up to the full registered Resource Adequacy Capacity. The CAISO will generate a Proxy Bid or extend an Energy Bid or Self-Schedule to cover any RUC Award or Day-Ahead Schedule in the absence of any Self-Schedule or Economic Bid components, or to fill in any gaps between any Self-Schedule Bid and any Economic Bid components to cover a RUC Award or Day-Ahead Schedule. To the extent that an Energy Bid to the HASP/RTM is not accompanied by an Ancillary Services Bid, the CAISO will insert a Spinning Reserve and Non-Spinning Reserve Ancillary Services Bid at $ 0/MW for any certified Operating Reserve capacity. The CAISO will also generate a Self-Schedule Bid for any Generating Unit that has a Day-Ahead Schedule but has not submitted Bids in HASP/RTM, up to the quantity in the Day-Ahead Schedule. Throughout the Bid evaluation process, the Scheduling Coordinator shall have the ability to view the Bid and may choose to cancel the Bid, modify and re-submit the Bid, or leave the modified, conditionally modified or valid, conditionally valid Bid as is to be processed in the designated CAISO Market. The CAISO will not insert or extend any Bid for Regulation Up or Regulation Down in the Real-Time Market for a Use-Limited Resource except as provided in Section 40.6.8. The CAISO will not insert or extend a Spinning Reserve or Non-Spinning Reserve Ancillary Service Bid at $0 in the Real-Time Market for any certified Operating Reserve capacity of a resource unless that resource submits an Energy Bid and fails to submit an Ancillary Service Bid in the Real-Time Market.

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30.7.6.1 Validation of Ancillary Services Bids

Throughout the validation process described in Section 30.7, the CAISO will verify that each Ancillary Services Bid conforms to the content, format and syntax specified for the relevant Ancillary Service. If the Ancillary Services Bid does not so conform, the CAISO will send a notification to the Scheduling Coordinator notifying the Scheduling Coordinator of the errors in the Bids as described in Section 30.7. When the Bids are submitted, a technical validation will be performed to verify that the bid quantity of Regulation, Spinning Reserve, or Non-Spinning Reserve does not exceed the certified Ancillary Services capacity for Regulation, or Operating Reserves on the Generating Units, System Units, Participating Loads, Proxy Demand Resources, and external imports/exports bid. The Scheduling Coordinator will be notified within a reasonable time of any validation errors. For each error detected, an error message will be generated by the CAISO in the Scheduling Coordinator's notification screen, which will specify the nature of the error. The Scheduling Coordinator can then look at the notification messages to review the detailed list of errors, make changes, and resubmit if it is still within the CAISO's timing requirements.

The Scheduling Coordinator is also notified of successful validation. If a resource is awarded or has qualified Self-Provided Ancillary Services in the Day-Ahead Market, if no Energy Bid is submitted to cover the awarded or Self-Provided Ancillary Services by the Market Close of HASP and the RTM, the CAISO will generate or extend an Energy Bid as necessary to cover the awarded or Self-Provided Ancillary Services capacity using the registered values in the Master File and relevant fuel prices as described in the Business Practice Manuals for use in the HASP and IFM. If an AS Bid or Submission to Self-Provide an AS is submitted in the Real-Time Market for Spinning Reserve or Non-Spinning Reserve without an accompanying Energy Bid at all, the AS Bid or Submission to Self-Provide an Ancillary Service will be erased. If an AS Bid is submitted in the HASP or Real-Time Market for Spinning Reserve and Non-Spinning Reserve with only a partial Energy Bid for the AS capacity, the CAISO will generate an Energy Bid for the uncovered portions. If a Submission to Self-Provide an Ancillary Service is submitted in the HASP or Real-Time Market for Spinning Reserve and Non-Spinning Reserve with only a partial Energy Bid for the AS capacity bid in, the CAISO will not generate or extend an Energy Bid for the uncovered portions. For Generating Units with certified Regulation capacity, if there no Bid for Regulation in the Real-Time Market, but there is a Day-Ahead award for Regulation Up or Regulation Down or a submission to self-provide Regulation Up or Regulation Down, respectively, the CAISO will generate a Regulation Up or Regulation Down Bid at the default Ancillary Service Bid price of $0 up to the certified Regulation capacity for the Generating Unit minus any Regulation awarded or self-provided in the Day-Ahead. If there is a Bid for Regulation Up or Regulation Down in the Real-Time Market, the CAISO will increase the respective Bid up to the certified Regulation capacity for the Generating Unit minus any Regulation awarded or self-provided in the Day-Ahead. If a Self-Schedule amount is greater than the Regulation Limit for Regulation Up, the Regulation Up Bid will be erased.

Notwithstanding any of the provisions of Section 30.7.6.1 set forth above, the CAISO will not insert or extend any Bid for Regulation Up or Regulation Down in the Real-Time Market for a Use-Limited Resource except as provided in Section 40.6.8. The CAISO will not insert a Spinning Reserve and Non-Spinning Reserve Ancillary Service Bid at $0 in the Real-Time Market for any certified Operating Reserve capacity of a resource unless that resource submits an Energy Bid but fails to submit an Ancillary Service Bid in the Real-Time Market.

30.7.6.2 Treatment of Ancillary Services Bids

When Scheduling Coordinators bid into the Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve markets, they may submit Bids for the same capacity into as many of these markets as desired at the same time by providing the appropriate Bid information to the CAISO. The CAISO optimization will evaluate AS Bids simultaneously with Energy Bids. A Scheduling Coordinator may specify that its Bid applies only the markets it desires. A Scheduling Coordinator shall also have the ability to specify different capacity prices for the Spinning Reserve, Non-Spinning Reserve, and Regulation markets. A Scheduling Coordinator providing one or more Regulation Up, Regulation Down, Spinning Reserve or Non-Spinning Reserve services may not change the identification of the Generating Units or Proxy Demand Resources offered in the Day-Ahead Market or in the Real-Time Market for such services unless specifically approved by the CAISO (except with respect to System Units, if any, in which case Scheduling Coordinators are required to identify and disclose the resource specific information for all Generating Units, Participating Loads, and Proxy Demand Resources constituting the System Unit for which Bids and Submissions to Self-Provide Ancillary Services are submitted into the CAISO's Day-Ahead Market and Real-Time Market).

The following principles will apply in the treatment of Ancillary Services Bids in the CAISO Markets:

(a) not differentiate between bidders for Ancillary Services and Energy other than through cost, price, effectiveness, and capability to provide the Ancillary Service or Energy, and the required locational mix of Ancillary Services;

(b) select the bidders with most cost effective Bids for Ancillary Service capacity which meet its technical requirements, including location and operating capability to minimize the costs to users of the CAISO Controlled Grid;

(c) evaluate the Day-Ahead Bids over the twenty-four (24) Settlement Periods of the following Trading Day along with Energy, taking into account Transmission Constraints and AS Regional Limits;

(d) evaluate Import Bids along with internal resources;

(e) establish Real-Time Ancillary Service Awards through RTUC from imports and resources internal to the CAISO Balancing Authority Area at fifteen (15) minutes intervals to the hour of operation; and

(f) procure sufficient Ancillary Services in the Day-Ahead and Real-Time Markets to meet its forecasted requirements.

* * *

31.1 Bid Submission And Validation In The Day-Ahead Market

Bids, including Self-Schedules and Ancillary Services Bids, and Submissions to Self-Provide an Ancillary Service shall be submitted pursuant to the submission rules specified in Section 30. There is a single bid submission in which Scheduling Coordinators' Bids are used for purposes of the DAM, which includes the MPM-RRD, the IFM and RUC. Scheduling Coordinators may submit Bids for the DAM as early as seven (7) days prior to the applicable Trading Day up to Market Close of the DAM for the applicable Trading Day. The CAISO will validate all Bids submitted to the DAM pursuant to the procedures set forth in Section 30.7. Scheduling Coordinators must submit Bids for participation in the IFM for Resource Adequacy Capacity as required in Section 40.

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31.2.1 The Reliability And Market Power Mitigation Runs

The first run of the MPM-RRD procedures is the Competitive Constraints Run (CCR), in which only limits on transmission lines pre-designated as competitive are enforced. The only RMR Units considered in the CCR are Condition 1 RMR Units that have provided market Bids for the DAM and Condition 2 RMR Units when obligated to submit a Bid pursuant to an RMR Contract. The second run is the All Constraints Run (ACR), during which all Transmission Constraints that are expected to be enforced in the Integrated Forward Market are enforced. All RMR Units, Condition 1 and Condition 2, are considered in the ACR.

* * *

31.3 Integrated Forward Market

After the MPM-RRD and prior to RUC, the CAISO shall perform the IFM. The IFM (1) performs Unit Commitment and Congestion Management (2) clears mitigated or unmitigated Bids cleared in the MPM-

RRD as well as Bids that were not cleared in the MPM-RRD process against bid-in Demand, taking into account transmission limits and honoring technical and inter-temporal operating constraints, such as Minimum Run Times (3) and procures Ancillary Services to meet one hundred (100) percent of the CAISO Forecast of CAISO Demand requirements. The IFM utilizes a set of integrated programs that: (1) determine Day-Ahead Schedules and AS Awards, and related LMPs and ASMPs; and (2) optimally commits resources that are bid in to the DAM. The IFM utilizes a SCUC algorithm that optimizes Start-Up Costs, Minimum Load Costs, Transition Costs, and Energy Bids along with any Bids for Ancillary Services as well as Self-Schedules submitted by Scheduling Coordinators. The IFM selects the optimal MSG Configuration from a maximum of ten MSG Configurations of each Multi-Stage Generating Resource as mutually exclusive resources. If a Scheduling Coordinator submits a Self-Schedule or a Submission to Self-Provide Ancillary Services for a given MSG Configuration in a given Trading Hour, the IFM will consider the Start-Up Cost, Minimum Load Cost, and Transition Cost associated with any Economic Bids for other MSG Configurations as incremental costs between the other MSG Configurations and the self-scheduled MSG Configuration. In such cases, incremental costs are the additional costs incurred to transition or operate in an MSG Configuration in addition to the costs associated with the self-scheduled MSG Configuration. The IFM also provides for the optimal management of Use-Limited Resources. The ELS Resources committed through the ELC Process conducted two days before the day the IFM process is conducted for the next Trading Day as described in Section 31.7 are binding.

* * *

31.3.1.3 Reduction of Self-Scheduled LAP Demand

In the IFM, to the extent the market software cannot resolve a non-competitive Transmission Constraint utilizing Effective Economic Bids such that self-scheduled Load at the LAP level would otherwise be reduced to relieve the Transmission Constraint, the CAISO Market software will adjust Non-priced Quantities in accordance with the process and criteria described in Section 27.4.3. For this purpose the priority sequence, starting with the first type of Non-priced Quantity to be adjusted, will be: (a) Schedule the Energy from Self-Provided Ancillary Service Bids from capacity that is obligated to offer an Energy Bid under a must-offer obligation such as from an RMR Unit or a Resource Adequacy Resource. Consistent with Section 8.6.2, the CAISO Market software could also utilize the Energy from Self-Provided Ancillary

Service Bids from capacity that is not under a must-offer obligation such as from an RMR Unit or a Resource Adequacy Resource, to the extent the Scheduling Coordinator has submitted an Energy Bid for such capacity. The associated Energy Bid prices will be those resulting from the MPM-RRD process.(b) Relax the constraint consistent with Section 27.4.3.1, and establish prices consistent with Section 27.4.3.2. No constraints, including Transmission Constraints, on Interties with adjacent Balancing Authority Areas will be relaxed in this procedure.

* * *

31.3.3 Metered Subsystems

In clearing the IFM, the CAISO will not enforce Transmission Constraints within each MSS. The Full Network Model (FNM) includes a full model of MSS transmission networks used for power flow calculations and Transmission Constraint management in the IFM and RTM. Transmission Constraints (i.e. circuit ratings, thermal ratings, etc.) within the MSS, or at its boundaries, that are modeled in the FNM shall be monitored but not enforced in the operation of the CAISO Markets. If overloads are observed in the forward markets that are internal to the MSS or at the MSS boundaries and are attributable to MSS operations, the CAISO shall communicate such events to the Scheduling Coordinator for the MSS and coordinate any manual Re-dispatch required in Real-Time. If, independent of the CAISO, the Scheduling Coordinator for the MSS is unable to resolve Congestion internal to the MSS or at the MSS boundaries in Real-Time, the CAISO will use Exceptional Dispatch Instructions on resources that have been bid into the HASP and RTM to resolve the Congestion. Such costs will be allocated pursuant to the provisions specified in Section 11.5.6.2.5.2. The CAISO and MSS Operator shall develop specific procedures for each MSS to determine how Transmission Constraints will be handled. Costs associated with internal Congestion and Transmission Losses in the MSS will be the responsibility of the MSS Operator. The Scheduling Coordinator for the MSS shall be responsible for payment of Marginal Losses for transactions at any points of interconnection between the MSS and the CAISO Controlled Grid, and for the delivery of Energy to the MSS or from the MSS in accordance with the CAISO Tariff. For MSS Operators that elect Load following, the CAISO shall exclude the effect of Transmission Losses in the relevant MSS in the CAISO's calculation of loss sensitivity factors used to calculate LMPs.

31.4 CAISO Market Adjustments To Non-Priced Quantities In The IFM

All Self-Schedules are respected by SCUC to the maximum extent possible and are protected from curtailment in the Congestion Management process to the extent that there are Effective Economic Bids that can relieve Congestion. If all Effective Economic Bids in the IFM are exhausted, resource Self-Schedules between the resource's Minimum Load and the first Energy level of the first Energy Bid point will be subject to adjustments by the CAISO Market optimization based on the scheduling priorities listed below. This functionality of the optimization software is implemented through the setting of scheduling parameters as described in Section 27.4.3 and specified in Section 27.4.3.1 and the Business Practice Manuals. Through this process, imports and exports may be reduced to zero, Demand Bids may be reduced to zero, Price Taker Demand (LAP load) may be reduced, and Generation may be reduced to a lower operating limit (or Regulation Limit) (or to a lower Regulation Limit plus any qualified Regulation Down award or Self-Provided Ancillary Services, if applicable). Any Self-Schedules below the Minimum Load level are treated as fixed Self-Schedules and are not subject to these adjustments for Congestion Management. The provisions of this section shall apply only to the extent they do not conflict with any MSS Agreement. In accordance with Section 27.4.3.5 the resources submitted in valid TOR, ETC or Converted Rights Self-Schedules shall not be adjusted in the IFM in response to an insufficiency of Effective Economic Bids. Thus the adjustment sequence for the IFM from highest priority (last to be adjusted) to lowest priority (first to be adjusted), is as follows:

(a) Reliability Must Run (RMR) Generation pre-dispatch reduction;

(b) Day-Ahead TOR Self-Schedules reduction (balanced demand and supply reduction);

(c) Day-Ahead ETC and Converted Rights Self-Schedules reduction; different ETC priority levels will be observed based upon global ETC priorities provided to the CAISO by the Responsible PTOs;

(d) Internal Transmission Constraint relaxation for the IFM pursuant to Section 27.4.3.1;

(e) Other Self-Schedules of CAISO Demand reduction subject to Section 31.3.1.3, exports explicitly identified in a Resource Adequacy Plan to be served by

Resource Adequacy Capacity explicitly identified and linked in a Supply Plan to the exports, and Self-Schedules of exports at Scheduling Points explicitly sourced by non-Resource Adequacy Capacity;

(f) Self-Schedules of exports at Scheduling Points not explicitly sourced by non-Resource Adequacy Capacity, except those exports explicitly identified in a Resource Adequacy Plan to be served by Resource Adequacy Capacity explicitly identified and linked in a Supply Plan to the exports as set forth in Section 31.4(d);

(g) Day-Ahead Regulatory Must-Run Generation and Regulatory Must-Take Generation reduction;

(h) Other Self-Schedules of Supply reduction.

* * *

31.5.1.2 RUC Availability Bids

Scheduling Coordinators may only submit RUC Availability Bids for capacity (above the Minimum Load) for which they are also submitting an Energy Bid to participate in the IFM. Any available Resource Adequacy Capacity and ICPM Capacity will be optimized at $0/MW in RUC. For Multi-Stage Generating Resources that fail to submit a $0/MW per hour for the Resource Adequacy Capacity, the CAISO will insert the $0/MW per hour for the resource's Resource Adequacy Capacity at the MSG Configuration level up to the minimum of the Resource Adequacy Capacity or the PMax of the MSG Configuration. Scheduling Coordinators may submit non-zero RUC Availability Bids for the portion of a resource's capacity that is not Resource Adequacy Capacity or ICPM Capacity.

31.5.4 RUC Procurement Constraints

In addition to the resource constraints and Transmission Constraints employed by SCUC as discussed in Section 27.4.1, the CAISO shall employ the following three constraints in RUC:

(a) To ensure that sufficient RUC Capacity is procured to meet the CAISO Forecast of CAISO Demand, the CAISO will enforce the power balance between the total Supply, which includes Day-Ahead Schedules and RUC Capacity, and the total

Demand, which includes the CAISO Forecast of CAISO Demand and IFM export Schedules. The CAISO may adjust the CAISO Forecast of CAISO Demand to increase the RUC procurement target if there is AS Bid insufficiency in the IFM.

(b) To ensure that RUC will neither commit an excessive amount of Minimum Load Energy nor procure an excessive amount of RUC Capacity from Scheduling Points the CAISO will verify that the sum of Day-Ahead Schedules, Schedules of Generating Units, net imports, Participating Loads, and Proxy Demand Resources plus the Minimum Load Energy committed by RUC is not greater than a configurable percentage of the system CAISO Forecast of CAISO Demand.

(c) The CAISO can limit the amount of RUC Capacity it will procure from resources that could otherwise be started during the Operating Day based on operational factors such as: (1) historical confidence that a Short Start Unit actually starts when needed based on the assessment of the CAISO Operators of the historical performance of Short Start Units; (2) need to conserve the number of run-hours and number of starts per year for critical loading periods; and (3) seasonal constraints such as Overgeneration. The CAISO will verify that the total Day-Ahead Schedules and RUC Capacity from such resources is not greater than a configurable percentage of the total available capacity of all such resources.

31.5.5 Selection And Commitment Of RUC Capacity

Capacity that is not already scheduled in the IFM may be selected as RUC Capacity through the RUC process of the DAM. The RUC optimization will select RUC Capacity and produce nodal RUC Prices by minimizing total Bid cost based on RUC Availability Bids and Start-Up, Minimum Load Bids and Transition Costs. RUC will not consider Start-Up, Minimum Load Bids, or Transition Costs for resources already committed in the IFM. The RUC Capacity of a resource is the incremental amount of capacity selected in RUC above the resource’s Day-Ahead Schedule. The resource’s Day-Ahead Schedule plus its RUC Capacity comprise the resource’s RUC Schedule. The CAISO will only issue RUC Start-Up Instructions to resources committed in RUC that must receive a Start-Up Instruction in the Day-Ahead in order to be available to meet Real-Time Demand. RUC Schedules will be provided to Scheduling Coordinators even if a RUC Start-Up Instruction is not issued at that time. RUC shall not Shut Down resources scheduled through the IFM and RUC will not commit a Multi-Stage Generating Resource to a lower MSG Configuration that is unable to support the Energy scheduled in the IFM. If the RUC process cannot find a feasible solution given the resources committed in the IFM, the RUC process will adjust constraints as described in Section 31.5.4 to arrive at a feasible solution that accommodates all the resources committed in the IFM, and any necessary de-commitment of IFM committed units shall be effectuated through an Exceptional Dispatch.

31.6.4 [NOT USED]

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31.7 Extremely Long-Start Commitment Process

The CAISO shall perform the Extremely Long-Start Commitment Process (ELC Process) after the regular DAM results are posted. ELS Resources are flagged in the Master File and are the only resources eligible to be committed in the ELC Process. Each day after the DAM results are posted, the CAISO shall conduct the ELC Process to determine commitment of ELS Resources to be available to the CAISO Markets in the second day out. The CAISO will use the latest CAISO Forecast of CAISO Demand available to the CAISO for the Trading Day two days ahead of the current day that the ELC Process is executed. For commitment purposes for a resource whose Start-Up Time would exceed the definition of an ELS Resource based on the resource's initial condition and cooling time, the CAISO will consider DAM Bids from ELS Resources as Bids for the Trading Day two days ahead of the current day that the ELC Process is executed. The CAISO Operator shall use its operator judgment consistent with Good Utility Practice to determine whether ELS Resources for the second day in the 48-hour time period should be committed. The ELC Process does not dispatch Energy for the 48-hour time period and therefore the commitment instructions will not include megawatts schedules greater than the Minimum Load. ELS Resources receiving a commitment instruction are obligated to resubmit the same Bid in the next day's Day-Ahead Market. The CAISO Commitment Period or Self-Commitment Period determination for the ELS Resources depends on the DAM results and the Clean and Generated Bids, following the same rules that apply to other resources. All Commitment Intervals for the ELS Resources will be classified as CAISO Commitment Periods, unless there is a Self-Schedule or Self-Provided AS for that interval.

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33.2 The HASP Optimization

After the Market Close for the HASP and RTM for the relevant Trading Hour, the Bids have been validated and the MPM-RRD process has been performed, the HASP optimization determines feasible but non-binding HASP Advisory Schedules for Generating Units for each fifteen-minute interval of the Trading Hour, as well as binding hourly HASP Intertie Schedules and binding hourly HASP AS Awards from Non-Dynamic System Resources for that Trading Hour. The HASP may also commit resources whose Start-Up Times are within the immediately following Trading Hour. The HASP, like the other runs of the RTUC, utilizes the same SCUC optimization and Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 as the IFM, with the Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 updated to reflect changes in system conditions as appropriate, to ensure that HASP Intertie Schedules are feasible. Instead of clearing against Demand Bids as in the IFM, the HASP clears Supply against the CAISO Forecast of CAISO Demand plus submitted Export Bids, to the extent the Export Bids are selected in the MPM-RRD process. The HASP optimization also factors in forecasted unscheduled flow at the Interties. The HASP optimization produces Settlement prices for hourly imports and exports to and from the CAISO Balancing Authority Area reflected in the HASP Intertie Schedule and for the HASP AS Awards for System Resources.

33.3 Treatment Of Self-Schedules In HASP

The HASP optimization clears Bids, including Self-Schedules, while preserving all priorities in this process consistent with Section 34.10. The HASP optimization does not adjust submitted Self-Schedules unless it is not possible to balance Supply and the CAISO Forecast of CAISO Demand plus Export Bids and manage Congestion using the available Economic Bids, in which case the HASP performs non-economic adjustments to Self-Schedules. The MWh quantities of Self-Schedules of Supply that clear in the HASP constitute a feasible Dispatch for the RTM at the time HASP is run, but the HASP results do not constitute a final Schedule for Generating Units because these resources may be adjusted non-economically in the RTD if necessary to manage Congestion and clear Supply and Demand. Self-Schedules submitted for Generating Units that clear in the HASP will be issued HASP Advisory Schedules. Scheduling Coordinators representing Participating Intermittent Resources whose output is being used to satisfy a resource adequacy requirement must submit Self-Schedules in HASP in accordance with the forecast provided by the independent forecast service provider. The submission of a change to an ETC Self-Schedule beyond the deadline specified in Section 16.9.1, that is permitted pursuant to the terms of the applicable ETC, shall not be deemed to be an unbalanced ETC Self-Schedule for the purposes of Settlement, consistent with the ETC and TOR Self-Schedule Settlement treatment described in Section 11.5.7.

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33.8.1 Eligibility To Set The HASP Intertie LMP

All Generating Units, Participating Loads, System Resources, System Units, or COGs subject to the provisions in Section 27.7 with Bids, including Generated Bids, that are unconstrained due to Ramp Rates or other temporal constraints are eligible to set the HASP Intertie LMP, provided that (a) the Generating Unit or Resource-Specific System Resource is Dispatched between its Minimum Operating Limit and the highest MW value in its Economic Bid or Generated Bid, or (b) the Participating Load, non-Resource-Specific System Resource, or System Unit is Dispatched between zero (0) MW and the highest MW value in its Economic Bid or Generated Bid. If (a) a resource's Dispatch is constrained by its Minimum Operating Limit or the highest MW value in its Economic Bid or Generated Bid, (b) the CAISO enforces a resource-specific constraint on the resource due to an RMR or Exceptional Dispatch, or (c) the resource's full Ramping capability is constraining its Dispatch for additional Energy in a target interval, the resource cannot be marginal and thus is not eligible to set the HASP Intertie LMP. Resources identified as MSS Load following resources are not eligible to set the HASP Intertie LMP. A Constrained Output Generator that has the ability to be committed or shut off within the immediately following Trading Hour in which a specific HASP run is conducted will be eligible to set the Dispatch Interval LMP if any portion of its Energy is necessary to serve Demand. Dispatches of Regulation resources to a Dispatch Operating Point by SCED will be eligible to set the HASP Intertie LMP.

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34. Real-Time Market

The RTM is the market conducted by the CAISO during any given Operating Day in which Scheduling Coordinators may provide Real-Time Imbalance Energy and Ancillary Services. The Real-Time Market consists of the Real-Time Unit Commitment (RTUC), the Short-Term Unit Commitment (STUC) and the Real-Time Dispatch (RTD) processes. The Short-Term Unit Commitment (STUC) runs once per hour near the top of the hour and utilizes the SCUC optimization to commit Medium Start, Short Start and Fast Start Units to meet the CAISO Demand Forecast. The CAISO shall dispatch all resources, including Participating Load and Proxy Demand Resource, pursuant to submitted Bids or pursuant to the provisions below on Exceptional Dispatch. In Real-Time, resources are required to follow Real-Time Dispatch Instructions. In any given Trading Hour, the STUC may commit resources for the third fifteen-minute interval of the current Trading Hour and extending into the next four Trading Hours. The RTUC runs every fifteen (15) minutes and utilizes the SCUC optimization to commit Fast Start and some Short Start Units and to procure any needed AS on a fifteen-minute basis. In any given Trading Hour, the RTUC may commit resources in the four to seven subsequent fifteen-minute intervals, depending on when during the hour the run occurs. Not all resources committed in a given STUC or RTUC run will necessarily receive CAISO commitment instructions immediately, because during the Trading Day the CAISO may issue a commitment instruction to a resource only at the latest possible time that allows the resource to be ready to provide Energy when it is expected to be needed. The RTD uses a Security Constrained Economic Dispatch (SCED) algorithm every five minutes throughout the Trading Hour to determine optimal Dispatch Instructions to balance Supply and Demand. Updates to the Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 used in the RTM optimization include current estimates of real-time unscheduled flow at the Interties. In any given five-minute interval, the RTD optimization looks ahead over multiple five minute intervals, but the CAISO issues Dispatch Instructions only for the next target five-minute Interval. The RTUC, STUC and RTD processes of the RTM use the same Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 used in the DAM and the HASP, subject to any necessary updates of the Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 pursuant to changes in grid conditions after the DAM has run. In the case of Multi-Stage Generating Resources, the RTM procedures will optimize Transition Costs in addition to the Start-Up and Minimum Load Costs. If a Scheduling Coordinator submits a Self-Schedule or a Submission to Self-Provide Ancillary Services for a given MSG Configuration in a given Trading Hour, all of the RTM processes will consider the Start-Up Cost, Minimum Load Cost, and Transition Cost associated with any

Economic Bids for other MSG Configurations as incremental costs between the other MSG Configurations and the self-scheduled MSG Configuration. In such cases, incremental costs are the additional costs incurred to transition or operate in an MSG Configuration in addition to the costs associated with the self-scheduled MSG Configuration.

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34.2 Real-Time Unit Commitment

The Real-Time Unit Commitment (RTUC) process uses SCUC and is run every fifteen (15) minutes to: (1) make commitment decisions for Fast Start and Short Start Units having Start-Up Times within the applicable time periods described below in this section, and (2) procure required additional Ancillary Services and calculate ASMP used for settling procured Ancillary Service capacity for the next fifteen-minute Real-Time Ancillary Service interval. In any fifteen (15) minute RTUC interval that falls within a time period in which a Multi-Stage Generating Resource is transitioning from one MSG Configuration to another MSG Configuration, the CAISO: (1) will not award any incremental Ancillary Services; (2) will disqualify any Day-Ahead Ancillary Services Awards; (3) will disqualify Day-Ahead qualified Submissions to Self-Provide Ancillary Services Award, and (4) will disqualify Submissions to Self-Provide Ancillary Services in RTM. For Multi-Stage Generating Resources the RTUC will issue a binding Transition Instruction separately from the binding Start-Up or Shut Down instructions. The RTUC can also be run with the Contingency Flag activated, in which case the RTUC can commit Contingency Only Operating Reserves. If RTUC is run without the Contingency Flag activated, it cannot commit Contingency Only Operating Reserves. RTUC is run at the following time intervals: (1) at approximately 7.5 minutes prior to the next Trading Hour, in conjunction with the HASP run, for T-45 minutes to T+60 minutes; (2) at approximately 7.5 minutes into the current hour for T-30 minutes to T+60 minutes; (3) at approximately 22.5 minutes into the current hour for T-15 minutes to T+60 minutes; and (4) at approximately 37.5 minutes into the current hour for T to T+60 minutes where T is the beginning of the next Trade Hour. The HASP, described in Section 33, is a special RTUC run that is performed at approximately 7.5 minutes before each hour and has the additional responsibility of: (1) pre-dispatching Energy and awarding Ancillary Services for hourly dispatched System Resources for the Trading Hour that begins 67.5 minutes later, and (2) performing the necessary MPM-RRD for that Trading Hour. A Day-Ahead Schedule or RUC

Schedule for an MSG Configuration that is later impacted by the resource's derate or outages, will be reconsidered in the RTUC process taking into consideration the impacts of the derate or outage on the available MSG Configurations.

34.2.1 Commitment Of Fast Start And Short Start Units

RTUC produces binding and advisory Start-Up and Shut-Down Dispatch Instructions for Fast Start and Short Start Units that have Start-Up Times that would allow the resource to be committed prior to the end of the relevant time period of the RTUC run as described in Section 34.2. A Start-Up Dispatch Instruction is considered binding in any given RTUC run if the Start-Up Time of the resource is such that there would not be sufficient time for a subsequent RTUC run to Start-Up the resource. A Start-Up Instruction is considered advisory if it is not binding, such that the resource could achieve its target Start-Up Time as determined in the current RTUC run in a subsequent RTUC run based on its Start-Up Time. A Shut-Down Instruction is considered binding if the resource could achieve the target Shut-Down Time as determined in the current RTUC in a subsequent RTUC run. A Shut-Down Dispatch Instruction is considered advisory if the resource Shut-Down Instruction is not binding such that the resource could achieve its target Shut-Down time as determined in the current RTUC run in a subsequent RTUC run. A binding Dispatch Instruction that results in a change in Commitment Status will be issued, in accordance with Section 6.3, after review and acceptance of the Start-Up Instruction by the CAISO Operator. An advisory Dispatch Instruction changing the Commitment Status of a resource may be modified by the CAISO Operator to a binding Dispatch Instruction and communicated in accordance with Section 6.3 after review and acceptance by the CAISO Operator. Only binding and not advisory Dispatch Instructions will be issued by the CAISO. For Multi-Stage Generating Resources the CAISO will also issue binding Transition Instructions when the Multi-Stage Generating Resource must change from one MSG Configuration to another. A Transition Instruction is considered binding in any given RTUC run if the Transition Time for the Multi-Stage Generating Resource is such that there would not be sufficient time for a subsequent RTUC run to transition the resource.

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34.3.1 Real-Time Economic Dispatch

RTED mode of operation for RTD normally runs every five (5) minutes starting at approximately 7.5 minutes prior to the start of the next Dispatch Interval and produces binding Dispatch Instructions for Energy for the next Dispatch Interval and advisory Dispatch Instructions for multiple future Dispatch Intervals through at least the next Trading Hour. After being reviewed by the CAISO Operator, only binding Dispatch Instructions are communicated for the next Dispatch Interval in accordance with Section 6.3. RTED will produce a Dispatch Interval LMP for each PNode for the Dispatch Interval associated with the binding Dispatch Instructions. The RTED Dispatch target is the middle of the interval between five (5) minutes boundary points.

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34.3.3 Real-Time Manual Dispatch

RTMD mode of operation for RTD is a merit-order run activated upon CAISO Operator request as a backup process in case the normal RTED process fails to converge. The RTMD run will provide the CAISO Operator a list of resources and quantity of MW available for Dispatch in merit-order based on Operational Ramp Rate but otherwise ignores Transmission Losses and Transmission Constraints. The CAISO Operator may dispatch resources from the list by identifying the quantity of Imbalance Energy that is required for the system and/or directly selecting resources from the merit order taking into consideration actual operating conditions. After Dispatches have been selected, reviewed and accepted by the CAISO Operator, Dispatch Instructions will be communicated in accordance with Section 6.3. While the RTMD mode is being used for Dispatch a uniform five-minute MCP will be produced for all PNodes based on the merit order Dispatch. Until RTMD is actually run and RTMD-based Dispatch Instructions are issued after RTED fails to converge, all five-minute Dispatch Interval LMPs will be set to the last LMP at each Node produced by the last RTED run that converged.

* * *

34.4 Short-Term Unit Commitment

At the top of each Trading Hour, immediately after the RTUC run is completed, the CAISO performs an approximately five (5) hour Short-Term Unit Commitment (STUC) run using SCUC and the CAISO Forecast of CAISO Demand to commit Medium Start Units and Short Start Units with Start-Up Times greater than the time period covered by the RTUC described in Section 34.2. The STUC looks ahead over a period of at least three hours beyond the Trading Hour for which the RTUC optimization was run, and will utilize Bids available from other CAISO Markets for that Trading Hour for these additional hours. The CAISO revises these replicated Bids each time the hourly STUC is run, to utilize the most recently available Bids. A Start-Up Instruction produced by STUC is considered binding if the resource could not achieve the target Start-Up Time as determined in the current STUC run in a subsequent RTUC or STUC run as a result of the Start-Up Time of the resource. A Start-Up Instruction produced by STUC is considered advisory if it is not binding, such that the resource could achieve its target start time as determined in the current RTUC run in a subsequent STUC or RTUC run based on its Start-Up Time. A binding Dispatch Instruction produced by STUC that results in a change in Commitment Status will be issued, in accordance with Section 6.3, after review and acceptance of the Start-Up Instruction by the CAISO Operator. The STUC will only decommit a resource to the extent that resource's physical characteristics allow it to be cycled in the same approximately five (5) hour look-ahed time period for which it was previously committed. STUC does not produce Locational Marginal Prices for Settlement. A Day-Ahead Schedule or RUC Schedule for an MSG Configuration that is later impacted by the resource's derate or outages, will be reconsidered in the STUC process taking into consideration the impacts of the derate or outage on the available MSG Configurations.

* * *

34.5 General Dispatch Principles

The CAISO shall conduct all Dispatch activities consistent with the following principles:

(1) The CAISO shall issue AGC instructions electronically as often as every four (4) seconds from its Energy Management System (EMS) to resources providing Regulation and on Automatic Generation Control to meet NERC and WECC performance requirements;

(2) In each run of the RTED or RTCD the objective will be to meet the projected Energy requirements over the applicable forward-looking time period of that run, subject to transmission and resource operational constraints, taking into account the short term CAISO Forecast of CAISO Demand adjusted as necessary by the

CAISO Operator to reflect scheduled changes to Interchange and non-dispatchable resources in subsequent Dispatch Intervals;

(3) Dispatch Instructions will be based on Energy Bids for those resources that are capable of intra-hour adjustments and will be determined through the use of SCED except when the CAISO must utilize the RTMD;

(4) When dispatching Energy from awarded Ancillary Service capacity the CAISO will not differentiate between Ancillary Services procured by the CAISO and Submissions to Self-Provide an Ancillary Service;

(5) The Dispatch Instructions of a resource for a subsequent Dispatch Interval shall take as a point of reference the actual output obtained from either the State Estimator solution or the last valid telemetry measurement and the resource's operational ramping capability. For Multi-Stage Generating Resources the determination of the point of reference is further affected by the MSG Configuration and the information contained in the Transition Matrix;

(6) In determining the Dispatch Instructions for a target Dispatch Interval while at the same time achieving the objective to minimize Dispatch costs to meet the forecasted conditions of the entire forward-looking time period, the Dispatch for the target Dispatch Interval will be affected by: (a) Dispatch Instructions in prior intervals, (b) actual output of the resource, (c) forecasted conditions in subsequent intervals within the forward-looking time period of the optimization, and (d) operational constraints of the resource, such that a resource may be dispatched in a direction for the immediate target Dispatch Interval that is different than the direction of change in Energy needs from the current Dispatch Interval to the next immediate Dispatch Interval, considering the applicable MSG Configuration;

(7) Through Start-Up Instructions the CAISO may instruct resources to start up or shut down, or may reduce Load for Participating Loads and Proxy Demand Resources, over the forward-looking time period for the RTM based on submitted

Bids, Start-Up Costs and Minimum Load Costs, Pumping Costs and Pump Shut-Down Costs, as appropriate for the resource, or for Multi-Stage Generating Resource as appropriate for the applicable MSG Configuration, consistent with operating characteristics of the resources that the SCED is able to enforce. In making Start-Up or Shut-Down decisions in the RTM, the CAISO may factor in limitations on number of run hours or Start-Ups of a resource to avoid exhausting its maximum number of run hours or Start-Ups during periods other than peak loading conditions;

(8) The CAISO shall only start up resources that can start within the applicable time periods of the various CAISO Markets Processes that comprise the RTM;

(9) The RTM optimization may result in resources being shut down consistent with their Bids and operating characteristics provided that: (a) the resource does not need to be on-line to provide Energy, (b) the resource is able to start up within the applicable time periods of the processes that comprise the RTM, (c) the Generating Unit is not providing Regulation or Spinning Reserve, and (d) Generating Units online providing Non-Spinning Reserve may be shut down if they can be brought up within ten (10) minutes as such resources are needed to be online to provide Non-Spinning Reserves; (10) For resources that are both providing Regulation and have submitted Energy Bids for the RTM, Dispatch Instructions will be based on the Regulation Ramp Rate of the resource rather than the Operational Ramp Rate if the Dispatch Operating Point remains within the Regulating Range. The Regulating Range will limit the Ramping of Dispatch Instructions issued to resources that are providing Regulation;

(11) For Multi-Stage Generating Resources the CAISO will issue Dispatch Instructions by Resource ID and Configuration ID;

(12) The CAISO may issue Transition Instructions to instruct resources to transition from one MSG Configuration to another over the forward-looking time period for the RTM based on submitted Bids, Transition Costs and Minimum Load Costs,

as appropriate for the MSG Configurations involved in the MSG Transition, consistent with Transition Matrix and operating characteristics of these MSG Configurations. The RTM optimization will factor in limitations on Minimum Up Time and Minimum Down Time defined for each MSG configuration and Minimum Up Time and Minimum Down Time at the Generating Unit or Dynamic Resource-Specific System Resource.

* * *

34.7 Utilization Of The Energy Bids

The CAISO uses Energy Bids for the following purposes: (i) satisfying Real-Time Energy needs; (ii) mitigating Congestion; (iii) maintaining aggregate Regulation reserve capability in Real-Time; (iv) allowing recovery of Operating Reserves utilized in Real-Time operations; (v) procuring Voltage Support required from resources beyond their power factor ranges in Real-Time; (vi) establishing LMPs; (vii) as the basis for Bid Cost Recovery; and (viii) to the extent a Real-Time Energy Bid Curve is submitted starting at minimum operating level for a Short Start Unit that is scheduled to be on-line, the RTM may Dispatch such a resource down to its minimum operating level and may issue a Shut-Down Instruction to the resource based on its Minimum Load Energy costs.

* * *

34.9.1 System Reliability Exceptional Dispatches

The CAISO may issue a manual Exceptional Dispatch for Generating Units, System Units, Participating Loads, Proxy Demand Resources, Dynamic System Resources, and Condition 2 RMR Units pursuant to Section 41.9, in addition to or instead of resources with a Day-Ahead Schedule dispatched by RTM optimization software during a System Emergency, or to prevent an imminent System Emergency or a situation that threatens System Reliability and cannot be addressed by the RTM optimization and system modeling. To the extent possible, the CAISO shall utilize available and effective Bids from resources before dispatching resources without Bids. To deal with any threats to System Reliability, the CAISO may also issue a manual Exceptional Dispatch in the Real-Time for Non-Dynamic System Resources that have not been or would not be selected by the RTM for Dispatch, but for which the relevant Scheduling Coordinator has submitted a Bid into the HASP.

34.9.2 Other Exceptional Dispatch

The CAISO may also issue manual Exceptional Dispatches for resources in addition to or instead of resources with a Day-Ahead Schedule or dispatched by the RTM optimization software to: (1) perform Ancillary Services testing; (2) perform pre-commercial operation testing for Generating Units; (3) perform periodic testing of Generating Units, including PMax testing; (4) mitigate for Overgeneration; (5) provide for Black Start; (6) provide for Voltage Support; (7) accommodate TOR or ETC Self-Schedule changes after the Market Close of the HASP; (8) reverse a commitment instruction issued through the IFM that is no longer optimal as determined through RUC; or (9) in the event of a Market Disruption, to prevent a Market Disruption, or to minimize the extent of a Market Disruption; or (10) reverse the operating mode of a Pumped-Storage Hydro Unit. The CAISO will not consider Start-Up Costs, Minimum Load Costs, or Energy Bids in connection with the issuance of Exceptional Dispatches to perform Ancillary Services testing, to perform PMax testing, or to perform pre-commercial operation testing for Generating Units.

* * *

34.15.1 Resource Constraints Version

The SCED shall enforce the following resource physical constraints:

(a) Minimum and maximum operating resource limits. Outages and limitations due to transmission clearances shall be reflected in these limits. The more restrictive operating or regulating limit shall be used for resources providing Regulation so that the SCED shall not Dispatch them outside their Regulating Range.

(b) Forbidden Operating Regions. When ramping in the Forbidden Operating Region, the implicit ramp rate will be used as determined based on the time it takes for the resource to cross its Forbidden Operating Region. A resource can only be ramped through a Forbidden Operating Region after being dispatched into a Forbidden Operation Region. The CAISO will not Dispatch a resource within its Forbidden Operating Regions in the Real-Time Market, except that the CAISO may Dispatch the resource through the Forbidden Operating Region in the direction that the resource entered the Forbidden Operating Region at the maximum applicable Ramp Rate over consecutive Dispatch Intervals. A resource with a Forbidden Operating Region cannot provide Ancillary

Services in a particular fifteen (15) minute Dispatch Interval unless that resource can complete its transit through the relevant Forbidden Operating Region within that particular Dispatch Interval.

(c) Operational Ramp Rates and Start-Up Times. The submitted Operational Ramp Rate for resources shall be used as the basis for all Dispatch Instructions, provided that the Dispatch Operating Point for resources that are providing Regulation remains within their applicable Regulating Range. The Regulating Range will limit the Ramping of Dispatch Instructions issued to resources that are providing Regulation. The Ramp Rate for Non-Dynamic System Resources cleared in the HASP will not be observed. Rather, the ramp of the Non-Dynamic System Resource will respect inter-Balancing Authority Area Ramping conventions established by WECC. Ramp Rates for Dynamic System Resources will be observed like Participating Generators in the RTD. Each Energy Bid shall be Dispatched only up to the amount of Imbalance Energy that can be provided within the Dispatch Interval based on the applicable Operational Ramp Rate. The Dispatch Instruction shall consider the relevant Start-Up Time as, if the resource is off-line, the relevant Operational Ramp Rate function, and any other resource constraints or prior commitments such as Schedule changes across hours and previous Dispatch Instructions. The Start-Up Time shall be determined from the Start-Up Time function and when the resource was last shut down. The Start-Up Time shall not apply if the corresponding resource is on-line or expected to start.

(d) Maximum number of daily Start-Ups. The SCED shall not cause a resource to exceed its daily maximum number of Start-Ups.

(e) Minimum Run Time and Down Time. The SCED shall not start up off-line resources before their Minimum Down Time expires and shall not shut down on-line resources before their Minimum Run Time expires. For Multi-Stage Generating Resources these requirements shall be observed both for the Generating Unit or Dynamic Resource-Specific System Resource and MSG Configuration.

(f) Operating (Spinning and Non-Spinning) Reserve. The SCED shall Dispatch Spinning and Non-Spinning Reserve subject to the limitations set forth in Section 34.16.3.

(g) Non-Dynamic System Resources. If Dispatched, each Non-Dynamic System Resource flagged for hourly pre-dispatch in the next Trading Hour shall be Dispatched to operate at a constant level over the entire Trading Hour. The HASP shall perform the hourly pre-dispatch for each Trading Hour once prior to the Operating Hour. The hourly pre-dispatch shall not subsequently be revised by the SCED and the resulting HASP Intertie Schedules are financially binding and are settled pursuant to Section 11.4.

(h) Daily Energy use limitation to the extent that Energy limitation is expressed in a resource's Bid. If the Energy Limits are violated for purposes of Exceptional Dispatches for System Reliability, the Bid will be settled as provided in Section 11.5.6.1.

* * *

34.15.6 Intra-Hour Exceptional Dispatches

For the special case where an Exceptional Dispatch begins in the new hour and the rules above would result in the violation of the resource's inter-temporal constraint(s), the following rules are applied and the Energy is settled as Exceptional Dispatch Energy as described in Section 11.5.6.

(a) If the ramp time is greater than one hour or greater than what can be achieved when RTM receives the constraint, RTM starts the ramp at the earliest possible time and continues Ramping the resource in the new Trading Hour.

(b) If the ramp time results in starting the ramp less than ten (10) minutes before the start of the hour, RTM instead starts the ramp at ten (10) minutes before the start of the hour and ramps the resource at a uniform rate so that it meets the constraint by the start time of the Exceptional Dispatch.

(c) If the new hour's Day-Ahead Schedule is beyond the Exceptional Dispatch constraint, RTM resumes the basic Ramping rules after the Exceptional Dispatch constraint is met, but limits the Ramp Rate as necessary to ensure that the resource does not complete its ramp before ten (10) minutes after the hour.

* * *

34.16.3.4 Voltage Support

(a) Voltage Support provided from Generating Units shall meet the standards specified in this CAISO Tariff and Part E of Appendix K.

(b) The CAISO may Dispatch Generating Units to increase or decrease MVar output within power factor limits of established pursuant to Section 8.2.3.3 (or within other limits specified by the CAISO in any exemption granted pursuant to Section 8.2.3.3) at no cost to the CAISO when required for System Reliability.

(c) The CAISO 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 the CAISO Tariff.

(d) If Voltage Support is required in addition to that provided pursuant to Section 34.16.3.4 (b) and (c), the CAISO will reduce output of Participating Generators certified in accordance with Appendix K . The CAISO will select Participating Generators in the vicinity where such additional Voltage Support is required.

(e) The CAISO will monitor voltage levels at Interconnections to maintain them in accordance with the applicable inter-Balancing Authority Area agreements.

* * *

34.17.2 Dispatch Information To Be Supplied By SC

Each Scheduling Coordinator shall be responsible for the submission of Bids and Dispatch of Generation and Demand in accordance with its Day-Ahead Schedule. Each Scheduling Coordinator shall keep the CAISO apprised of any change or potential change in the current status of all Generating Units and Intertie Schedules. This will include any changes in Generating Unit capacity that could affect planned Dispatch and conditions that could affect the reliability of a Generating Unit. Each Scheduling Coordinator shall immediately pass to the CAISO any information which it receives from a Generator which the Generator provides to the Scheduling Coordinator pursuant to Sections 34.11.1 and 34.11.2.

Each Scheduling Coordinator shall immediately pass to the CAISO any information it receives from a MSS Operator which the MSS Operator provides to the Scheduling Coordinator regarding any change or potential change in the current status of all Generating Units, System Units and Intertie Schedules. This information includes any changes in MSS System Units and Generating Unit capacity that could affect planned Dispatch and conditions that could affect the reliability of the System Unit or Generating Unit.

* * *

34.19.2.3 Eligibility to Set the Real-Time LMP

All Generating Units, Participating Loads, Proxy Demand Resources, Dynamic System Resources, System Units, or COGs subject to the provisions in Section 27.7, with Bids, including Generated Bids, that are unconstrained due to Ramp Rates or other temporal constraints are eligible to set the LMP, provided that (a) a Generating Unit or a Dynamic Resource-Specific System Resource is Dispatched between its Minimum Operating Limit and the highest MW value in its Economic Bid or Generated Bid, or (b) a Participating Load, a Proxy Demand Resource, a Dynamic System Resource that is not a Resource-Specific System Resource, or a System Unit is Dispatched between zero (0) MW and the highest MW value within its submitted Economic Bid range or Generated Bid. If a resource is Dispatched below its Minimum Operating Limit or above the highest MW value in its Economic Bid range or Generated Bid, or the CAISO enforces a resource-specific constraint on the resource due to an RMR or Exceptional Dispatch, the resource will not be eligible to set the LMP. Resources identified as MSS Load following resources are not eligible to set the LMP. A resource constrained at an upper or lower operating limit or dispatched for a quantity of Energy such that its full Ramping capability is constraining the ability of the resource to be dispatched for additional Energy in target interval, cannot be marginal (i.e., it is constrained by the Ramping capability) and thus is not eligible to set the Dispatch Interval LMP. Non-Dynamic System Resources are not eligible to set the Dispatch Interval LMP. Dynamic System Resources are eligible to set the Dispatch Interval LMP. A Constrained Output Generator that has the ability to be committed or shut off within applicable time periods that comprise the RTM will be eligible to set the Dispatch Interval LMP if any portion of its Energy is necessary to serve Demand. Dispatches of Regulation resources by EMS in response to AGC will not set the RTM LMP. Dispatches of Regulation resources to a Dispatch Operating Point by RTM SCED will be eligible to set the RTM LMP.

* * *

36.13.6 Clearing Of The CRR Auction

The SFT used to clear the CRR Auction will utilize the same DC FNM and optimization algorithm as the corresponding CRR Allocation, except that nominations to the CRR Auction will have associated price-quantity bid curves. The CRR Auction SFT will use the bid prices in determining which CRRs to award when not all nominations are simultaneously feasible, will select the set of simultaneously feasible CRRs with the highest total auction value as determined by the CRR bids, and will calculate nodal prices at each PNode of the DC FNM. In the event that there are two or more identical bids for a specific combination of CRR Source and CRR Sink that affect an overloaded constraint, the CRR Auction optimization cannot distinguish these bids based on either effectiveness or price and therefore the CRR Auction optimization will award each CRR bidder a pro rata share of the CRRs that can be awarded based on the bid MW amounts. Based on the nodal prices calculated by the CRR Auction SFT, the CRR Market Clearing Price per MW for a specific CRR will equal the nodal price at the CRR Source minus the nodal price at the CRR Sink.

* * *

36.15 [NOT USED]

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37.2.1.1 Expected Conduct

Market Participants must comply with operating orders issued by the CAISO as authorized under the CAISO Tariff. For purposes of enforcement under this Section 37.2, an operating order shall be an order(s) from the CAISO directing a Market Participant to undertake, a single, clearly specified action (e.g., the operation of a specific device, or change in status of a particular Generating Unit) that is feasible and intended to resolve a specific operating condition. Deviation from an ADS Dispatch Instruction shall not constitute a violation of this Section 37.2.1.1. A Market Participant's failure to obey an operating order containing multiple instructions to address a specific operating condition will result in a single violation of Section 37.2. If some limitation prevents the Market Participant from fulfilling the action requested by the

CAISO or the action is otherwise infeasible, then the Market Participant must promptly and directly communicate the nature of any such limitation or infeasibility to the CAISO.

* * *

37.2.5 Enhancements And Exceptions

Except as otherwise specifically provided, penalty amounts shall be tripled for any violation of Section 37.2.1, Section 37.2.2 or Section 37.2.4 if a CAISO System Emergency exists at the time an operating order becomes effective or at any time during the Market Participant's non-performance. Notwithstanding the foregoing, violations of Section 37.2.1, Section 37.2.2 and Section 37.2.4 are subject to penalty under this Section 37.2 only to the extent that the CAISO has issued a separate and distinct non-automated Dispatch Instruction to the Market Participant. Any penalty amount that is tripled under this provision and that would exceed the $10,000 per day penalty limit shall not be levied against a Market Participant until the CAISO proposes and the Commission approves such an enhancement. A Market Participant that is subject to an enhanced penalty amount under this Section 37.2.5 may appeal that penalty amount to FERC if the Market Participant believes a mitigating circumstance not covered in Section 37.9.2 exists. The duty of the Market Participant to pay the enhanced penalty amount will be tolled until FERC renders its decision on the appeal.

* * *

37.4.1.1 Expected Conduct

A Market Participant shall notify the CAISO Control Center of any Outage reportable pursuant to Section 9.3.10.3.1 of a Generating Unit subject to Section 4.6 within sixty (60) minutes after the Outage is discovered.

* * *

37.4.3.1 Expected Conduct

As required by Section 9.3.10.6, a Market Participant must provide a detailed explanation of a Forced Outage within two (2) Business Days after the Operator initially notifies the CAISO pursuant to Section 9.3.10.3.1 of the change in maximum output capability. An Operator must promptly provide information requested by the CAISO to enable the CAISO to review the explanation submitted by the Operator and to prepare a report on the Forced Outage.

* * *

37.5.2.1 Expected Conduct

Market Participants shall provide complete and accurate Settlement Quality Meter Data for each Trading Hour and shall correct any errors in such data no later than forty-three (43) calendar days after the Trading Day (T+43C). The failure to provide complete and accurate Settlement Quality Meter Data, as required by Section 10 that causes an error to exist in such Settlement Quality Meter Data after forty-three (43) calendar days after the Trading Day (T+43C) shall be a violation of this rule. Scheduling Coordinators that fail to submit Scheduling Coordinator Estimated Settlement Quality Meter Data that is complete and based on a good faith estimate that reasonably represents Demand and/or Generation quantities for each Settlement Period as required by Section 10 and that results in an error that is discovered after forty three (43) calendar days after the Trading Day (T+43C) shall be a violation of this rule.

* * *

37.8.10 Review Of Determination

A Market Participant that receives a Sanction may obtain immediate review of the CAISO's determination by directly appealing to FERC, in accordance with FERC's rules and procedures. In such case, the applicable Scheduling Coordinator shall also dispute the Initial Settlement Statement T+7B containing the financial penalty, in accordance with Section 11. The Initial Settlement Statement T+7B dispute and appeal to FERC must be made in accordance with the timeline for raising disputes specified in Section 11.29.8. The penalty will be tolled until FERC renders its decision on the appeal. The disposition by FERC of such appeal shall be final, and no separate dispute of such Sanction may be initiated under Section 13, except as provided in Section 37.9.3.4. For the purpose of applying the time limitations set forth in Section 37.10.1, a Sanction will be considered assessed when it is included on an Initial Settlement Statement T+7B, whether or not the CAISO accepts a Scheduling Coordinator's dispute of such Initial Settlement Statement T+7B pending resolution of an appeal to FERC in accordance with this section or Section 37.9.3.3.

* * *

37.9.3.1 Settlement Statements

The CAISO will administer any penalties issued under this Section 37 through Initial Settlement Statements T+7B or Recalculation Settlement Statements, as relevant, issued to the responsible Scheduling Coordinator by the CAISO. Before invoicing a financial penalty through the Settlement process, the CAISO will provide a description of the penalty to the responsible Scheduling Coordinator and all Market Participants the Scheduling Coordinator represents that are liable for the penalty, when the CAISO has sufficient objective information to identify and verify responsibility of such Market Participants. The CAISO shall specify whether such penalty is modified pursuant to Section 37.2.5 or Section 37.4.4. The description shall include the identity of the Market Participant that committed the violation and the amount of the penalty. Where FERC has determined the Sanction, the CAISO will provide such of the above information as is provided to it by FERC. The CAISO also may publish this information under the CAISO Website after Recalculation Settlement Statements are issued.

* * *

37.11.1 Method For Calculating Inaccurate Meter Data Penalty

There is no Sanction for the submission of inaccurate Meter Data used for an Initial Settlement Statement T+ 7B. However, an error in submitted Meter Data that exists after forty three (43) calendar days after the Trading Day (T+43C) constitutes a Rule of Conduct violation. The level of the Sanction depends on whether the Scheduling Coordinator or the CAISO discovered the error. An increased penalty will apply for errors that are discovered by the CAISO.

Table A1 below shows how the level of the Sanction depends on the following factors: whether or not the Scheduling Coordinator finds the error; whether or not the Scheduling Coordinator owes the market, and whether or not the CAISO performs a re-run of the market or produces a Recalculation Settlement Statement. If the CAISO issues a Recalculation Settlement Statement or performs a re-run, then Settlement to all Scheduling Coordinators is recalculated, and the impact of such re-runs on charges assessed will be considered. A penalty charge equal to thirty (30) percent of the estimated value of the Energy error will apply if the Scheduling Coordinator discovers the error or seventy-five (75) percent of the estimated value of the Energy error if the CAISO discovers the error. Penalty assessment and disposition of penalty proceeds will be administered as described in Section 37.9.1 and Section 37.9.4 respectively. A Sanction will not be imposed unless such Sanction is more than $1,000 for at least one Trading Day during the period for which there was incomplete or inaccurate Meter Data.

Table A1 – Calculation of Inaccurate Meter Data Penalty When There Is A Recalculation Settlement Statement or re-run Case	Does SC Owe Market?	
Case 1: SC Identifies Inaccurate Meter Data	Yes	Penalty = (MWh x applicable price) x 0.30
Case 1: SC Identifies Inaccurate Meter Data	No	Penalty = (MWh x applicable price) x 0.30
Case 2: CAISO Identifies Inaccurate Meter Data	Yes	Penalty = (MWh x applicable price) x 0.75
Case 2: CAISO Identifies Inaccurate Meter Data	No	Penalty = (MWh x applicable price) x 0.75

Note to Table A1:

The applicable price will be the greater of: (1) the simple average of the relevant twelve (12) five-minute LMPs for each hour in which inaccurate meter data occurred; or (2) $10/MWh. The LMP used will be the values posted on OASIS for each Trading Hour of the applicable Trading Day period.

2. Method for Calculating Inaccurate Meter Data Penalty When there is not a Recalculation Settlement Statement or re-run.

If the CAISO does not perform a Recalculation Settlement Statement or re-run, for cases of inaccurate Meter Data, Table A2 will be used to determine and allocate penalty and any market adjustment amount. The market adjustment approximates the financial impact on the market; however, it does not completely reflect all the Settlement consequences of inaccurately submitted Meter Data. The approximated value of the inaccurate Meter Data in question will be calculated and returned to the market based on the average of the pro rata share of Unaccounted for Energy (UFE) charged in the utility Service Area during the period of the inaccurate Meter Data event. The thirty (30) percent or seventy-five (75) percent penalty will be distributed as discussed in Section 37.9.4. For cases where the CAISO does not perform a Recalculation Settlement Statement or re-run and the Scheduling Coordinator does not owe the market, then no market adjustment will be performed and no penalty will be assessed.

TABLE A2- Calculation Of Inaccurate Meter Data Penalty When There Is Not a Recalculation Settlement Statement or re-run Case	Does SC Owe Market?	CAISO does not perform a Recalculation Settlement Statement or re-run
Case 1: SC Identifies Inaccurate Meter Data	Yes	Market Adjustment = (MWh x applicable price) Penalty = (MWh x applicable price)) x 0.30
Case 1: SC Identifies Inaccurate Meter Data	No	No market adjustment will be made
Case 2: CAISO Identifies Inaccurate	Yes	Market Adjustment = (MWh x applicable price) Penalty = (MWh x applicable price) x 0.75

Meter Data		
Case 2: CAISO Identifies Inaccurate Meter Data	No	No market adjustment will be made

Notes to Table A2:

The applicable price will be the greater of: (1) the simple average of the relevant twelve (12) five-minute LMPs for each hour in which inaccurate meter data occurred; or (2) $10/MWh. The LMP used will be the value posted on OASIS for each Trading Hour of the applicable Trading Day.

A Sanction will be imposed only if the Sanction is more than $1,000 for at least one Trading Day during the period for which there was incomplete or inaccurate Meter Data.

If the error is to the detriment of the responsible Scheduling Coordinator (e.g., under-reported Generation or over-reported Demand), and the CAISO does not produce a Recalculation Settlement Statement or perform a re-run, then no market adjustment will be made and no penalty will be assessed. If the CAISO produces a Recalculation Settlement Statement or performs a re-run after the error is corrected, then the Scheduling Coordinator will be given credit for the additional Energy through the normal Settlement process. If the Scheduling Coordinator is paid for an error due to a Recalculation Settlement Statement or re-run, then a Sanction will be assessed to assure that Recalculation Settlement Statements or re-runs do not diminish the incentive to correct such errors. This Sanction would be thirty (30) percent of the Energy value of the error if the Scheduling Coordinator discovers the error or seventy-five (75) percent estimated value of the error if the CAISO discovers the error.

If the error is to the detriment of the market, then a charge equal to thirty (30) percent or seventy-five (75) percent of the estimated value of the error, as appropriate, will be added to the charge for the Energy. If there is no Recalculation Settlement Statement or re-run, then the cost of Energy supplied by the CAISO (and inappropriately charged to the market as Unaccounted for Energy) must be recovered as well, and the charge will be equal to one-hundred thirty (130) percent or one-hundred seventy five (175) percent of the estimated value of the error, as appropriate.

* * *

39.3.1 Conduct Regarding Bidding, Scheduling Or Facility Operation

Mitigation Measures may be applied to bidding, scheduling or operation of an Electric Facility or as specified in Section 39.3.1. 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 CAISO Markets if exercised from a position of market power. Accordingly, the CAISO shall monitor the CAISO 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 a CAISO 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 for an Electric Facility when it would be in the economic interest, absent market power, of the withholding entity to do so, (iii) declining Bids called upon by the CAISO (unless the CAISO 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 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 LMPs.

(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.

(4) Bidding practices that distort prices or uplift charges away from those expected in a competitive market, such as registering Start-Up Cost and Minimum Load Cost data or submitting Bid Costs on behalf of an Electric Facility that are unjustifiably high (relative to known operational characteristics and/or the known operating cost of the resource) or misrepresenting the physical operating capabilities of an Electric Facility resulting in uplift payments or prices significantly in excess of actual costs.

* * *

39.6.1.6.1 Gas Price Component of Projected Proxy Cost

For natural gas fired resources, the CAISO will calculate a gas price to be used in establishing maximum Start-Up Costs and Minimum Load Costs after the twenty-first day of each month and post it on the CAISO Website by the end of each calendar month. The price will be applicable for Scheduling Coordinators electing the Registered Cost option until a new gas price is calculated and posted on the CAISO Website. The gas price will be calculated as follows:

(1) Daily closing prices for monthly natural gas futures contracts at Henry Hub for the next calendar month are averaged over the first twenty-one (21) days of the month, resulting in a single average for the next calendar month.

(2) Daily prices for futures contracts for basis swaps at identified California delivery points, are averaged over the first twenty-one (21) days of the month for the identified California delivery points as set forth in the Business Practice Manual.

(3) For each of the California delivery point, the average Henry Hub and basis swap prices are combined and will be used as the baseline gas price applicable for calculating the caps for Start-Up and Minimum Load costs for resources electing the Registered Cost option. The most geographically appropriate will apply to a particular resource.

(4) The applicable intra-state gas transportation charge as set forth in the Business Practice Manual will be added to the baseline gas price for each resource that elects the Registered Cost option to create a final gas price for calculating the caps for Start-Up and Minimum Load Costs for each such resource.}

For non-gas fired resources, the Projected Proxy Costs for Start-Up Costs and Minimum Load Costs will be calculated using the information contained in the Master File used for calculating the Proxy Cost, as set forth in the Business Practice Manual.

* * *

39.7 Local Market Power Mitigation For Energy Bids

Local Market Power Mitigation is based on a periodic assessment and designation of Transmission Constraints as competitive or non-competitive. Such periodic assessment will be performed at a minimum on an annual basis and potentially more frequently if needed due to changes in system conditions, network topology, or market performance. Any changes in Transmission Constraints designations will be publicly noticed prior to making the change. Upon determination that an ad hoc assessment is warranted, the CAISO will notice Market Participants that such an assessment will be performed. The determination whether a unit is being dispatched to relieve Congestion on a competitive or non-competitive Transmission Constraint is based on two preliminary market runs that are performed prior to the actual pricing run of the market and are described in Sections 31 and 33 for the DAM and RTM, respectively.

39.7.1 Calculation Of Default Energy Bids Version

Default Energy Bids shall be calculated by the CAISO, for the on-peak hours and off-peak hours for both the DAM and RTMs, pursuant to one of the methodologies described in this Section. The Scheduling Coordinator for each Generating Unit owner or Participating Load must rank order the following options of calculating the Default Energy Bid starting with its preferred method. The Scheduling Coordinator must provide the data necessary for determining the Variable Costs unless the Negotiated Rate Option precedes the Variable Cost Option in the rank order, in which case the Scheduling Coordinator must have a negotiated rate established with the Independent Entity charged with calculating the Default Energy Bid. If no rank order is specified for a Generating Unit or Participating Load, then the default rank order of (1)

Variable Cost Option, (2) Negotiated Rate Option, (3) LMP Option will be applied. For the first ninety (90) days after changes to resource status and MSG Configurations as specified in Section 27.8.3, including the first ninety (90) days after the effective date of Section 27.8.3, the Default Energy Bid option for the resource is limited to the Negotiated Rate Option or the Variable Cost Option.

* * *

39.7.1.1.1 Incremental Fuel Cost Calculation Under the Variable Cost Option

For natural gas-fueled units, incremental fuel cost is calculated based on an incremental heat rate curve multiplied by the natural gas price calculated as described below.

Resource owners shall submit to the CAISO average heat rates (Btu/kWh) measured for at least two (2) and up to eleven (11) generating operating points (MW), where the first and last operating points refer to the minimum and maximum operating levels (i.e., PMin and PMax), respectively. The average heat rate curve formed by the (Btu/kWh, MW) pairs is a piece-wise linear curve between operating points, and two (2) average heat rate pairs yield one (1) incremental heat rate segment that spans two (2) consecutive operating points. The incremental heat rates (Btu/kWh) in the incremental heat rate curve are calculated by converting the average heat rates submitted by resource owners to the CAISO to requirements of heat input (Btu/h) for each of the operating points and dividing the changes in requirements of heat input from one (1) operating point to the next by the changes in MW between two (2) consecutive operating points as specified in the Business Practice Manual. For each segment representing operating levels below eighty (80) percent of the unit's PMax, the incremental heat rate is limited to the maximum of the average heat rates for the two (2) operating points used to calculate the incremental heat rate segment.

The unit's final incremental fuel cost curve is calculated by multiplying this incremental heat rate curve by the applicable natural gas price, and then, if necessary, applying a left-to-right adjustment to ensure that the final incremental cost curve is monotonically non-decreasing.

For non-natural gas-fueled units, incremental fuel cost is calculated based on an average cost curve as described below.

Resource owners for non-natural gas-fueled units shall submit to the CAISO average fuel costs ($/MW) measured for at least two (2) and up to eleven (11) generating operating points (MW), where the first and last operating points refer to the minimum and maximum operating levels (i.e., PMin and PMax), respectively. The average cost curve formed by the ($/MWh, MW) pairs is a piece-wise linear curve between operating points, and two (2) average cost pairs yield one (1) incremental cost segment that spans two (2) consecutive operating points. For each segment representing operating levels below eighty (80) percent of the unit's PMax, the incremental cost rate is limited to the maximum of the average cost rates for the two (2) operating points used to calculate the incremental cost segment. The unit's final incremental fuel cost curve is then adjusted, if necessary, applying a left-to-right adjustment to ensure that the final incremental cost curve is monotonically non-decreasing.

Heat rate curves and average cost curves shall be stored, updated, and validated in the Master File. To calculate the natural gas price, the CAISO will use different gas price indices for the Day-Ahead Market and the Real-Time Market and each gas price index will be calculated using at least two prices from two or more of the following publications: Natural Gas Intelligence, SNL Energy/BTU's Daily Gas Wire, Platt's Gas Daily and the Intercontinental Exchange. If a gas price index is unavailable for any reason, the CAISO will use the most recent available gas price index. For the Day-Ahead Market, the CAISO will update the gas price index between 19:00 and 22:00 Pacific Time using natural gas prices published two days prior to the applicable Trading Day, unless gas prices are not published on that day, in which case the CAISO will use the most recently published prices that are available. For the Real-Time Market, the CAISO will update gas price indices between the hours of 19:00 and 22:00 Pacific Time using natural gas prices published one day prior to the applicable Trading Day, unless gas prices are not published on that day, in which case the CAISO will use the most recently published prices that are available.

39.7.1.2 LMP Option

The CAISO will calculate the LMP Option for the Default Energy Bid as a weighted average of the lowest quartile of LMPs at the Generating Unit PNode in periods when the unit was Dispatched during the preceding ninety (90) day period for which LMPs that have passed the price validation and correction process set forth in Section 35 are available. The weighted average will be calculated based on the quantities Dispatched within each segment of the Default Energy Bid curve. Each Bid segment created under the LMP Option for Default Energy Bids will be subject to a feasibility test, as set forth in a Business Practice Manual, to determine whether there are a sufficient number of data points to allow for the calculation of an LMP based Default Energy Bid. The feasibility test is designed to avoid excessive volatility of the Default Energy Bid under the LMP Option that could result when calculated based on a relatively small number of prices.

* * *

39.7.2.1 Timing of Assessments

The CAISO will complete the first assessment of competitiveness of Transmission Constraints prior to the effective date of this provision. Constraint designations resulting from the first assessment will be applied in the MPM-RRD mechanism on the day this CAISO Tariff becomes effective and will not be changed until a subsequent assessment has been performed. The CAISO may perform additional competitive constraint assessments during the year if changes in transmission infrastructure, generation resources, or Load, in the CAISO Balancing Authority Area and adjacent Balancing Authority Areas suggest material changes in market conditions or if market outcomes are observed that are inconsistent with competitive market outcomes. The CAISO will calculate and post path designations not less than once prior to the effective date of this tariff provision and not less than four (4) times each year thereafter to provide timely seasonal path designations.

39.7.2.2 Criteria

A Transmission Constraint will be deemed competitive if no three unaffiliated suppliers are jointly pivotal in relieving congestion on that constraint. The determination of whether or not the pivotal supplier criteria for an individual constraint are violated will be assessed using the Feasibility Index described in Section 39.7.2.4. Assessment of competitiveness will be performed assuming various system conditions potentially including but not limited to season, load, planned transmission and resource outages. If an individual constraint fails the pivotal supplier criteria under any of these system conditions, the constraint will be deemed uncompetitive for the entire year under all system conditions until a subsequent assessment deems the constraint competitive. In general, a constraint may be an individual transmission line or a collection of lines that create a distinct Transmission Constraint. For purposes of the competitive assessment, the set of constraints that will be included in the network model are those modeled along with transmission limits expected to be enforced in clearing the CAISO Markets.

* * *

39.10 Mitigation Of Exceptional Dispatches Of Resources

During the period commencing on the effective date of this section and ending at midnight on the last day of the fourth calendar month following such effective date, the CAISO shall apply Mitigation Measures to all Exceptional Dispatches eligible for an Exceptional Dispatch ICPM designation under Section 43.1.5. During the period commencing on the first day of the fifth calendar month following the effective date of this section and ending at midnight on the last day of the twenty-fourth calendar month following such effective date, the CAISO shall apply Mitigation Measures to Exceptional Dispatches of resources when such resources are committed or dispatched under Exceptional Dispatch for purposes of: (1) addressing reliability requirements related to non-competitive Transmission Constraints; and (2) addressing unit-specific environmental constraints not incorporated into the Full Network Model or the CAISO's market software that affect the dispatch of Generating Units in the Sacramento Delta and are commonly known as "Delta Dispatch". After the last day of the twenty-fourth calendar month following the effective date of this section, this entire Section 39.10 and the entirety of related Section 11.5.6.7, Section 43.1.5, and Section 43.2.6 shall no longer apply.

* * *

40.3.1.2 Local Capacity Technical Study Contingencies.

The Local Capacity Technical Study shall assess the following Contingencies: **Contingency Component(s)**
NERC/WECC Performance Level A – No Contingencies
<u>NERC/WECC Performance Level B – Loss of a single element</u> 1. Generator (G-1) 2. Transmission Circuit (L-1) 3. Transformer (T-1) 4. Single Pole (dc) Line

5. G-1 system readjusted L-1
<u>NERC/WECC Performance Level C – Loss of two or more elements</u> 3. L-1 system readjusted G-1 3. G-1 system readjusted T-1 or T-1 system readjusted G-1 3. L-1 system readjusted T-1 or T-1 system readjusted L-1 3. G-1 system readjusted G-1 3. L-1 system readjusted L-1 4. Bipolar (dc) Line 5. Two circuits (Common Mode) L-2 WECC-S3. Two generators (Common Mode) G-2
<u>D – Extreme event – loss of two or more elements</u> Any B1-4 system readjusted (Common Mode) L-2

* * *

40.5.1 Day Ahead Scheduling And Bidding Requirements

(1) Scheduling Coordinators on behalf of Modified Reserve Sharing LSEs serving Load within the CAISO Balancing Authority Area for whom they submit Demand Bids shall submit into the IFM Bids or Self-Schedules for Demand equal to one hundred (100) percent and for Supply equal to one hundred and fifteen (115) percent of the hourly Demand Forecasts for each Modified Reserve Sharing LSE it represents for each Trading Hour for the next Trading Day. Subject to Section 40.5.5, the resources included in a Self-Schedule or a Bid in each Trading Hour to satisfy one hundred and fifteen percent (115%) of the Modified Reserve Sharing LSE's hourly Demand Forecasts will be deemed Resource Adequacy Resources and (a) shall be comprised of those resources listed in the Modified Reserve Sharing LSE's monthly Resource Adequacy Plan and (b) shall include all Local Capacity Area Resources listed in the Modified Reserve Sharing LSE's

annual Resource Adequacy Plan, if any, except to the extent the Local Capacity Area Resources, if any, are unavailable due to any Outages or reductions in capacity reported to the CAISO in accordance with this CAISO Tariff.

(i) Local Capacity Area Resources physically capable of operating must submit: (a) Economic Bids for Energy and/or Self-Schedules for all their Resource Adequacy Capacity and (b) Economic Bids for Ancillary Services and/or a Submission to Self-Provide Ancillary Services for all of their Resource Adequacy Capacity that is certified to provide Ancillary Services. For Local Resource Adequacy Capacity that is certified to provide Ancillary Services and is not covered by a Submission to Self-Provide Ancillary Services, the resource must submit Economic Bids for each Ancillary Service for which the resource is certified. For Resource Adequacy Capacity subject to this requirement for which no Economic Energy Bid or Self-Schedule has been submitted, the CAISO shall insert a Generated Bid in accordance with Section 40.6.8. For Resource Adequacy Capacity subject to this requirement for which no Economic Bids for Ancillary Services or Submissions to Self-Provide Ancillary Services have been submitted, the CAISO shall insert a Generated Bid in accordance with Section 40.6.8 for each Ancillary Service the resource is certified to provide. However, to the extent the Generating Unit providing Local Capacity Area Resource capacity constitutes a Use-Limited Resource under Section 40.6.4, the provisions of Section 40.6.4 will apply.

(ii) Resource Adequacy Resource must participate in the RUC to the extent that the resource has available Resource Adequacy Capacity that was offered into the IFM and is not reflected in an IFM Schedule. Resource Adequacy Capacity participating in RUC will be optimized using zero dollar ($0/MW-hour) RUC Availability Bid.

(iii) Capacity from Resource Adequacy Resources selected in RUC will not be eligible to receive a RUC Availability Payment.

(iv) Through the IFM co-optimization process, the CAISO will utilize available Local Capacity Area Resource Adequacy Capacity to provide Energy or Ancillary Services in the most efficient manner to clear the Energy market, manage congestion and procure required Ancillary Services. In so doing the IFM will honor submitted Energy Self-Schedules of the Local Capacity Area Resource Adequacy Capacity of the Modified Reserve Sharing LSE unless the CAISO is unable to satisfy one hundred (100) percent of the Ancillary Services requirements. In such cases the CAISO may curtail all or a portion of a submitted Energy Self-Schedule to allow Ancillary Service-certified Local Capacity Area Resource Adequacy Capacity to be used to meet the Ancillary Service requirements. The CAISO will not curtail for the purpose of meeting Ancillary Service requirements a Self-Schedule of a resource internal to a Metered Subsystem that was submitted by the Scheduling Coordinator for that Metered Subsystem. If the IFM reduces the Energy Self-Schedule of Resource Adequacy Capacity to provide an Ancillary Service, the Ancillary Service Marginal Price for that Ancillary Service will be calculated in accordance with Section 27.1.2 using the Ancillary Service Bids submitted by the Scheduling Coordinator for the Resource Adequacy Resource or inserted by the CAISO pursuant to this Section 40.5.1, and using the resource's Generated Energy Bid to determine the Resource Adequacy Resource's opportunity cost of Energy. If the Scheduling Coordinator for the Modified Reserve Sharing LSE's Resource Adequacy Resource believes that the opportunity cost of Energy based on the Resource Adequacy Resource's Generated Energy Bid is insufficient to compensate for the resource's actual opportunity cost, the Scheduling Coordinator may submit evidence justifying the increased amount to the CAISO and to the FERC no later than seven (7) days after the end of the month in which the submitted Energy Self-Schedule was reduced by the CAISO to provide an Ancillary Service. The CAISO will treat such information as confidential and will apply the procedures in Section 20.4 of this CAISO Tariff with regard to requests for disclosure of such information. The CAISO shall pay the higher opportunity costs after those amounts have been approved by FERC.

(2) Resource Adequacy Resources of Modified Reserve Sharing LSEs that do not clear in the IFM or are not committed in RUC shall have no further offer requirements in HASP or Real-Time, except under System Emergencies as provided in this CAISO Tariff.

(3) Resource Adequacy Resources committed by the CAISO must maintain that commitment through Real-Time. In the event of a Forced Outage on a Resource Adequacy Resource committed in the Day-Ahead Market to provide Energy, the Scheduling Coordinator for the Modified Reserve Sharing LSE will have up to the next HASP bidding opportunity, plus one hour, to replace the lesser of: (i) the committed resource suffering the Forced Outage, (ii) the quantity of Energy committed in the Day-Ahead Market, or (iii) one hundred and seven (107) percent of the hourly forecast Demand.

* * *

40.5.2 Demand Forecast Accuracy

On a monthly basis, the CAISO will review Meter Data to evaluate the accuracy or quality of the hourly Day-Ahead Demand Forecasts submitted by the Scheduling Coordinator on behalf of Modified Reserve Sharing LSEs. If the CAISO determines, based on its review, that one or more Demand Forecasts materially under-forecasts the Demand of the Modified Reserve Sharing LSEs for whom the Scheduling Coordinator schedules, after accounting for weather adjustments, the CAISO will notify the Scheduling Coordinator of the deficiency and will cooperate with the Scheduling Coordinator and Modified Reserve

Sharing LSE(s) to revise its Demand Forecast protocols or criteria. If the material deficiency affects ten (10) hourly Demand Forecasts over a minimum of two (2) non-consecutive Business Days within a month, the CAISO may: (i) inform State of California authorities including, but not necessarily limited to, the California Legislature, and identify the Modified Reserve Sharing LSE(s) represented by the Scheduling Coordinator and (ii) assign to the Scheduling Coordinator responsibility for all tier 1 RUC charges as specified in Section 11.8.6.5 to address the uncertainty caused by the Scheduling Coordinator's deficient hourly Demand Forecasts until the deficiency is addressed.

* * *

40.6.2 Real-Time Availability

Resource Adequacy Resources that have received an IFM Schedule for Energy or Ancillary Services or a RUC Schedule for all or part of their Resource Adequacy Capacity must remain available to the CAISO through Real-Time for Trading Hours for which they receive an IFM or RUC schedule, including any Resource Adequacy Capacity of such resources that is not included in an IFM Schedule or RUC Schedule, except for Resource Adequacy Capacity that is subject to Section 40.6.4.

Short Start Units or Long Start Units that are Resource Adequacy Resources that do not have an IFM Schedule or a RUC Schedule for any of their Resource Adequacy Capacity for a given Trading Hour may be required to be available to the CAISO through Real-Time as specified in Sections 40.6.3 and 40.6.7. Resource Adequacy Resources with Resource Adequacy Capacity that is required to be available to the CAISO through Real-Time and does not have an IFM Schedule or a RUC Schedule for a given Trading Hour must submit to the RTM for that Trading hour: (a) Energy Bids and Self-Schedules for the full amount of the available Resource Adequacy Capacity, including capacity for which it has submitted Ancillary Services Bids or Submissions to Self-Provide Ancillary Services; and (b) Ancillary Services Bids and Submissions to Self-Provide Ancillary Services for the full amount of the available Ancillary Service-certified Resource Adequacy Capacity and for each Ancillary Service for which the resource is certified, including capacity for which it has submitted Energy Bids and Self-Schedules. The CAISO will insert Generated Bids in accordance with Section 40.6.8 for any Resource Adequacy Vapacity subject to the above requirements for which the resource has failed to submit the appropriate bids to the RTM.

The CAISO will honor submitted Energy Self-Schedules of Resource Adequacy Capacity unless the CAISO is unable to satisfy one hundred (100) percent of its Ancillary Services requirements. In such cases, the CAISO may curtail all or a portion of a submitted Energy Self-Schedule to allow Ancillary Service-certified Resource Adequacy Capacity to be used to meet the Ancillary Service requirements, as long as such curtailment does not lead to a real-time shortfall in energy supply. If the CAISO reduces a submitted Real-Time Energy Self-Schedule for Resource Adequacy Capacity when that capacity is needed to meet an Ancillary Services requirement, the Ancillary Service Marginal Price for that capacity will be calculated in accordance with Sections 27.1.2 and 40.6.1.

* * *

40.6.4.1 Registration of Use-Limited Resources

Hydroelectric Generating Units, Proxy Demand Resources, and Participating Load, including Pumping Load, are deemed to be Use-Limited Resources for purposes of this Section 40 and are not required to submit the application described in this Section 40.6.4.1. Scheduling Coordinators for other Use-Limited Resources, must provide the CAISO an application in the form specified on the CAISO Website requesting registration of a specifically identified resource as a Use-Limited Resource. This application shall include specific operating data and supporting documentation including, but not limited to:

(1) a detailed explanation of why the resource is subject to operating limitations;

(2) historical data to show attainable MWhs for each 24-hour period during the preceding year, including, as applicable, environmental restrictions for NOx, SOx, or other factors; and

(3) further data or other information as may be requested by the CAISO to understand the operating characteristics of the unit.

Within five (5) Business Days after receipt of the application, the CAISO will respond to the Scheduling Coordinator as to whether or not the CAISO agrees that the facility is eligible to be a Use-Limited Resource. If the CAISO determines the facility is not a Use-Limited Resource, the Scheduling Coordinator may challenge that determination in accordance with the CAISO ADR Procedures.

* * *

40.6.8 Use Of Generated Bids

Prior to completion of the Day-Ahead Market, the CAISO will determine if Resource Adequacy Capacity subject to the requirements of Sections 40.5.1 or 40.6.1 and for which the CAISO has not received notification of an Outage has not been reflected in a Bid and will insert a Generated Bid for such capacity into the CAISO Day-Ahead Market. Prior to running the Real-Time Market, the CAISO will determine if Resource Adequacy Capacity subject to the requirements of Section 40.6.2 and for which the CAISO has not received notification of an Outage has not been reflected in a Bid and will insert a Generated Bid for such capacity into the Real-Time Market. If a Scheduling Coordinator for an RA Resource submits a partial bid for the resource's RA Capacity, the CAISO will insert a Generated Bid only for the remaining RA Capacity. In addition, the CAISO will determine if all dispatchable Resource Adequacy Capacity from Short Start Units, not otherwise selected in the IFM or RUC, is reflected in a Bid into the Real-Time Market and will insert a Generated Bid for any remaining dispatchable Resource Adequacy Capacity for which the CAISO has not received notification of an Outage. A Generated Bid for Energy will be calculated as provided in the Business Practice Manuals. A Generated Bid for Ancillary Services will equal zero dollars ($0/MW-hour). Notwithstanding any of the provisions of Section 40.6.8 set forth above, the CAISO will not insert any Bid in the Real-Time Market required under this Section 40 for a Resource Adequacy Resource that is a Use-Limited Resource unless the resource submits an Energy Bid and fails to submit an Ancillary Service Bid.

* * *

41.5.1 Day-Ahead And HASP RMR Dispatch

RMR Dispatches will be determined in accordance with the RMR Contract, the MPM-RRD process addressed in Sections 31 and 33 and through manual RMR Dispatch Notices to meet Applicable Reliability Criteria.

The CAISO will notify Scheduling Coordinators for RMR Units of the amount and time of Energy requirements from specific RMR Units in the Trading Day prior to or at the same time as the Day-Ahead Schedules and AS and RUC Awards are published, to the extent that the CAISO is aware of such requirements, through an RMR Dispatch Notice or flagged RMR Dispatch in the IFM Day-Ahead Schedule. The CAISO may also issue RMR Dispatch Notices after Market Close of the DAM and through

Dispatch Instructions flagged as RMR Dispatches in the Real-Time Market. The Energy to be delivered for each Trading Hour pursuant to the RMR Dispatch Notice an RMR Dispatch in the IFM or Real-Time shall be referred to as the RMR Energy. Scheduling Coordinators may submit Bids in the DAM or the HASP for RMR Units operating under Condition 1 of the RMR Contract in accordance with the bidding rules applicable to non-RMR Units. A Bid submitted in the DAM or the HASP for a Condition 1 RMR Unit shall be deemed to be a notice of intent to substitute a market transaction for the amount of MWh specified in each Bid for each Trading Hour pursuant to Section 5.2 of the RMR Contract. In the event the CAISO issues an RMR Dispatch Notice or an RMR Dispatch in the IFM or Real-Time Market for any Trading Hour, any MWh quantities cleared through Competitive Constraints Run of the MPM-RRD shall be considered as a market transaction in accordance with the RMR Contract. RMR Units operating as Condition 2 RMR Units may not submit Bids until and unless the CAISO issues an RMR Dispatch Notice or issues an RMR Dispatch in the IFM, in which case a Condition 2 RMR Unit shall submit Bids in accordance with the RMR Contract in the next available market for the Trading Hours specified in the RMR Dispatch Notice or Day-Ahead Schedule.

* * *

43.1.2.1 LSE Opportunity to Resolve Collective Deficiency in Local Capacity Area Resources

Where the CAISO determines that a need for ICPM Capacity exists under Section 43.1.2, but prior to any designation of ICPM Capacity, the CAISO shall issue a Market Notice identifying the deficient Local Capacity Area and the quantity of capacity that would permit the deficient Local Capacity Area to comply with the Local Capacity Technical Study criteria provided in Section 40.3.1.1 and, where only specific resources are effective to resolve the Reliability Criteria deficiency, the CAISO shall provide the identity of such resources. Any Scheduling Coordinator may submit a revised annual Resource Adequacy Plan within thirty (30) days of the beginning of the Resource Adequacy Compliance Year demonstrating procurement of additional Local Capacity Area Resources consistent with the Market Notice issued under this Section.

Any Scheduling Coordinator that provides such additional Local Capacity Area Resources consistent with the Market Notice under this Section shall have its share of any ICPM procurement costs under Section 43.7.3 reduced on a proportionate basis. If the full quantity of capacity is not reported to the CAISO under revised annual Resource Adequacy Plans in accordance with this Section, the CAISO may designate ICPM Capacity sufficient to alleviate the deficiency.

* * *

43.6.3 Market Payments

In addition to the ICPM Capacity Payment identified in Section 43.6, ICPM resources shall be entitled to retain any revenues received as a result of their selection in the CAISO Markets, provided, however, that ICPM resources are required to participate in the RUC process will be optimized using a zero ($0) dollar RUC Availability Bid and are not eligible to receive compensation through the RUC process.

* * *

43.7.1 LSE Shortage Of Local Capacity Area Resources In Annual Plan

If the CAISO makes ICPM designations under Section 43.1.1.1 to address a shortage resulting from the failure of a Scheduling Coordinator for an LSE to identify sufficient Local Capacity Area Resources to meet its applicable Local Capacity Area capacity requirements in its annual Resource Adequacy Plan, then the CAISO shall allocate the total costs of the ICPM Capacity Payments for such ICPM designations (for the full term of those ICPM designations) pro rata to each Scheduling Coordinator for an LSE based on the ratio of its Local Capacity Area Resource Deficiency to the sum of the deficiency of Local Capacity Area Resources in the deficient Local Capacity Area(s) within a TAC Area. The Local Capacity Resource Area Deficiency under this Section shall be computed on a monthly basis and the ICPM Capacity Payments allocated based on deficiencies during the month(s) covered by the ICPM designation(s).

* * *

44. [NOT USED]

44.1 [NOT USED]

44.2 [NOT USED]

44.3 [NOT USED[

APPENDIX A

MASTER DEFINITION SUPPLEMENT

- **Aggregated Participating Load**

An aggregation at one or more Participating Load Locations, created by the CAISO in consultation with the relevant Participating Load, for the purposes of enabling participation of the Participating Load in the CAISO Markets like Generation by submitting Supply Bids when offering Curtailable Demand and as non-Participating Load by submitting Demand Bids to consume in the Day-Ahead Market only.

* * *

- All Constraints Run (ACR)

The second optimization run of the MPM-RRD process through which all Transmission Constraints that are expected to be enforced in the market-clearing processes (IFM, RUC, STUC, RTUC and RTD) are enforced.

* * *

- Available Transfer Capability (ATC)

The available capacity of a given transmission path, in MW, after subtraction of capacity associated with Existing Contracts and Transmission Ownership Rights from that path's Operating Transfer Capability established consistent with CAISO and WECC transmission capacity rating guidelines, further described in Appendix L.

* * *

- CAISO Audit Committee

A committee of the CAISO Governing Board appointed pursuant to Article IV, Section 5 of the CAISO bylaws to (1) review the CAISO's annual independent audit, (2) report to the CAISO Governing Board on such audit, and (3) monitor compliance with the CAISO Code of Conduct.

* * *

- Competitive Constraints Run (CCR)

The first optimization run of the MPM-RRD process through which only pre-designated competitive constraints are enforced.

* * *

- Congestion

A characteristic of the transmission system produced by a binding Transmission Constraint to the optimum economic dispatch to meet Demand such that the LMP, exclusive of Marginal Cost of Losses, at different Locations of the transmission system is not equal.

* * *

- [NOT USED]

* * *

- Curtailable Demand

Demand from a Participating Load or Aggregated Participating Load that can be curtailed at the direction of the CAISO in the Real-Time Dispatch of the CAISO Controlled Grid.

* * *

- Day-Ahead Inter-SC Trade Period

The period commencing seven (7) days prior to the applicable Trading Day and ending at noon on the day prior to that Trading Day, during which time the CAISO will accept Inter-SC Trades of Energy for the DAM from Scheduling Coordinators.

* * *

- Delivery Network Upgrades

Transmission facilities at or beyond the Point of Interconnection, other than Reliability Network Upgrades, identified in the Interconnection Studies to relieve Transmission Constraints on the CAISO Controlled Grid.

* * *

- Estimated Aggregate Liability (EAL)

The sum of a Market Participant's known and reasonably estimated potential liabilities for a specified time period arising from charges described in the CAISO Tariff, as provided for in Section 12.

* * *

- E-Tag

An electronic tag associated with an Interchange Schedule in accordance with the requirements of WECC.

* * *

- Forward Scheduling Charge

The component of the Grid Management Charge that provides for the recovery of the CAISO's costs, including, but not limited to, the costs of providing the ability to Scheduling Coordinators to submit a Bid for Energy and Ancillary Services and the cost of processing accepted Ancillary Services Bids. The formula for determining the Forward Scheduling Charge is set forth in Appendix F, Schedule 1, Part A.

* * *

- Full Network Model (FNM)

A computer-based model that includes all CAISO Balancing Authority Area transmission network (Load and Generating Unit) busses, Transmission Constraints, and Intertie busses between the CAISO Balancing Authority Area and interconnected Balancing Authority Areas. The FNM models the transmission facilities internal to the CAISO Balancing Authority Area as elements of a looped network and models the CAISO Balancing Authority Area Interties with interconnected Balancing Authority Areas in a radial fashion as specified in Section 27.5.

* * *

- 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 Utility Distribution Company or MSS Operator located in a PTO Service Territory. Gross Load shall exclude (1) Load with respect to which the Wheeling Access Charge is payable; (2) Load that is exempt from the Access Charge pursuant to Section 4.1 of Appendix I; and (3) the portion of the Load of an individual retail customer of a Utility Distribution Company, Small Utility Distribution Company, or MSS Operator that is served by a Generating Unit that: (a) is located on the customer's site or provides service to the customer's site through arrangements as authorized by Section 218 of the California Public Utilities Code; (b) is a qualifying small power production facility or qualifying cogeneration facility, as those terms are defined in the FERC's regulations implementing Section 201 of the Public Utility Regulatory Policies Act of 1978; and (c) secures Standby Service from a Participating TO under terms approved by a Local Regulatory Authority or FERC, as applicable, or can be curtailed concurrently with an Outage of the Generating Unit serving the Load. Gross Load forecasts consistent with filed Transmission Revenue Requirements will be provided by each Participating TO to the CAISO.

* * *

- HASP AS Award

An award for an import of Ancillary Services established through the HASP.

* * *

- Henry Hub

The pricing point for natural gas futures contracts.

* * *

- Locational Marginal Price (LMP)
The marginal cost ($/MWh) of serving the next increment of Demand at that PNode consistent with existing Transmission Constraints and the performance characteristics of resources.

* * *

- LSE
Load Serving Entity

* * *

- Market Participant
An entity, including a Scheduling Coordinator, who either: (1) participates in the CAISO Markets through the buying, selling, transmission, or distribution of Energy, capacity, or Ancillary Services into, out of, or through the CAISO Controlled Grid; or (2) is a CRR Holder or Candidate CRR Holder.

* * *

- Market Usage Charge
The component of the Grid Management Charge that provides for the recovery of the CAISO's costs, including, but not limited to, the costs for processing Day-Ahead, Hour-Ahead Scheduling Process and Real-Time Bids, maintaining the Open Access Same-Time Information System, monitoring market performance, ensuring generator compliance with market rules as defined in the CAISO Tariff and the Business Practice Manuals, and determining LMPs. The formula for determining the Market Usage Charge is set forth in Appendix F, Schedule 1, Part A.

* * *

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

(a) a credit agency downgrade;

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

(c) a bankruptcy filing;

(d) insolvency;

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

(f) any change in the financial condition of the Market Participant which exceeds a five (5) percent reduction in the Market Participant's Tangible Net Worth or Net Assets for the Market Participant's preceding fiscal year, calculated in accordance with generally accepted accounting practices.

* * *

- Net Procurement

The awarded amount (MW) of a given Ancillary Service in the Day-Ahead, HASP, and Real-Time Markets, minus the amount of that Ancillary Service associated with payments rescinded pursuant to any of the provisions of Section 8.10.2.

* * *

- Non-Dynamic System Resource

A System Resource that is not capable of submitting a Dynamic Schedule, or for which a Dynamic Schedule has not been submitted, which may be a Non-Dynamic Resource-Specific System Resource.

* * *

- Non-priced Quantity

As set forth in Section 27.4.3, a quantitative value in a CAISO Market that may be adjusted by the SCUC or SCED in the CAISO market optimizations but that does not have an associated bid price submitted by a Scheduling Coordinator. The Non-priced Quantities that may be so adjusted are: Energy Self-Schedules, Transmission Constraints, market energy balance constraints, Ancillary Service requirements, conditionally qualified and conditionally unqualified Ancillary Service self-provision, limits in RUC on minimum load energy, quick start capacity and minimum generation, Day-Ahead Energy Schedules resulting from the IFM, and estimated HASP Energy Self-Schedules used in RUC.

* * *

- Participating Generator

A Generator or other seller of Energy or Ancillary Services through a Scheduling Coordinator over the CAISO Controlled Grid (1) from a Generating Unit with a rated capacity of 1 MW or greater, (2) from a Generating Unit with a rated capacity of from 500 kW up to 1 MW for which the Generator elects to be a Participating Generator, or (3) from a Generating Unit providing Ancillary Services or submitting Energy Bids through an aggregation arrangement approved by the CAISO, which has undertaken to be bound by the terms of the CAISO Tariff, in the case of a Generator through a Participating Generator Agreement or QF PGA.

* * *

- Participating TO (PTO) Service Territory

The area in which an IOU, a Local Public Owned Electric Utility, or federal power marketing authority that has turned over its transmission facilities and/or Entitlements to CAISO Operational Control is obligated to provide electric service to Load. A PTO Service Territory may be comprised of the Service Areas of more than one Local Publicly Owned Electric Utility, if they are operating under an agreement with the CAISO for aggregation of their MSS and their MSS Operator is designated as the Participating TO.

* * *

- PTO Service Territory

Participating TO Service Territory.

* * *

- Qualifying Facility (QF)

A qualifying cogeneration facility or qualifying small power production facility, as defined in the Code of Federal Regulations, Title 18, Part 292 (18 C.F.R. § 292).

* * *

- Reliability Services Costs

The costs associated with services provided by the CAISO: 1) that are deemed by the CAISO as necessary to maintain reliable electric service in the CAISO Balancing Authority Area; and 2) whose costs are billed by the CAISO to the Participating TO pursuant to the CAISO Tariff. Reliability Services Costs include costs charged by the CAISO to a Participating TO associated with service provided under a Reliability Must-Run Contract, Exceptional Dispatches and Minimum Load Costs associated with units committed for local reliability requirements.

* * *

- RUC Zone

A forecast region representing a UDC or MSS Service Area, Local Capacity Area, or other collection of Nodes for which the CAISO has developed sufficient historical CAISO Demand and relevant weather data to perform a Demand Forecast for such area, for which as further provided in Section 31.5.3.7 the CAISO may adjust the CAISO Forecast of CAISO Demand to ensure that the RUC process produces adequate local capacity procurement.

* * *

- Scheduling Coordinator ID Code (SCID)

The individual Identification Code provided by the CAISO to the Scheduling Coordinator.

* * *

- Seasonal CRR Load Metric

The MW level of Load that is exceeded only in 0.5 percent of the hours for each season and time of use period based on the LSE's historical Load.

* * *

- Security Constrained Unit Commitment (SCUC)

An algorithm performed by a computer program over multiple hours that determines the Commitment Status and Day-Ahead Schedules, AS Awards, RUC Awards, HASP Intertie Schedules and Dispatch Instructions for selected resources and minimizes production costs (Start-Up, Minimum Load and Energy Bid Costs in IFM, HASP and RTM; Start-Up, Minimum Load and RUC Availability Bid Costs) while respecting the physical operating characteristics of selected resources and Transmission Constraints.

* * *

- Self-Commitment Period

The portion of a Commitment Period of a unit with an Energy Self- Schedule or a Submission to Self-Provide an Ancillary Service, except for Non-Spinning Reserve self-provision by a Fast Start Unit. The Self-Commitment Period may include Time Periods without Energy Self-Schedules or AS self-provision if it is determined by inference that the unit must be on due to Minimum Run Time, Minimum Down Time, or Maximum Daily Start-Up constraints.

* * *

- Settlement Period

For all CAISO 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.

* * *

- Settlements, Metering, And Client Relations Charge

The component of the Grid Management Charge that provides for the recovery of the CAISO'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 CAISO's Settlement, billing, and metering activities. Because this is a fixed charge per Scheduling Coordinator ID Code, 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.

* * *

- Shadow Price

The marginal value of relieving a particular constraint.

* * *

- Short-Term Unit Commitment (STUC)

The Unit Commitment procedure run at approximately 52.5 minutes prior to the applicable Trading Hour to determine whether certain Medium Start Units need to be started early to meet the Demand within the STUC forward-looking time period as described in Section 34.4 using the CAISO Forecast of CAISO Demand. The STUC produces a Unit Commitment solution for every 15-minute interval within the STUC forward-looking time periods and issues binding Start-Up Instructions only as necessary.

* * *

- Simultaneous Feasibility Test (SFT)

The process that the CAISO will conduct to ensure that allocated and auction CRRs do not exceed relevant Transmission Constraints as described in Section 36.4.2 and further described in the Business Practice Manuals.

* * *

- Spinning Reserve Obligation

The obligation of a Scheduling Coordinator to pay its share of costs incurred by the CAISO in procuring Spinning Reserve.

* * *

- System Resource

A group of resources, single resource, or a portion of a resource located outside of the CAISO Balancing Authority Area, or an allocated portion of a Balancing Authority Area's portfolio of generating resources that are either a static Interchange Schedule or directly responsive to that Balancing Authority Area's Automatic Generation Control (AGC) capable of providing Energy and/or Ancillary Services to the CAISO Balancing Authority Area, provided that if the System Resource is providing Regulation to the CAISO it is directly responsive to AGC.

* * *

- [NOT USED]

* * *

- Tolerance Band

The permitted area of variation for performance requirements of resources used for various purposes as further provided in the CAISO Tariff. The Tolerance Band is expressed in terms of Energy (MWh) for Generating Units, System Units and imports from Dynamic System Resources for each Settlement Interval and equals the greater of the absolute value of: (1) five (5) MW divided by the number of Settlement Intervals per Settlement Period or (2) three (3) percent of the relevant Generating Unit's, Dynamic System Resource's or System Unit's maximum output (PMax), as registered in the Master File, divided by the number of Settlement Intervals per Settlement Period. The maximum output (PMax) of a Dynamic System Resource will be established by agreement between the CAISO and the Scheduling Coordinator representing the Dynamic System Resource on an individual case basis, taking into account the number and size of the generating resources, or allocated portions of generating resources, that comprise the Dynamic System Resource.

The Tolerance Band is expressed in terms of Energy (MWh) for Participating Loads for each Settlement Interval and equals the greater of the absolute value of: (1) five (5) MW divided by the number of Settlement Intervals per Settlement Period or (2) three (3) percent of the applicable HASP Intertie Schedule or CAISO Dispatch amount divided by the number of Settlement Intervals per Settlement Period.

The Tolerance Band shall not be applied to Non-Dynamic System Resources.

* * *

- Total Transfer Capability (TTC)

The amount of power that can be transferred over an interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre-Contingency and post-Contingency system conditions.

* * *

- Transmission Constraints

Physical and operational limits on the transfer of electric power through transmission facilities.

- Transmission Constraints Enforcement Lists

Consist of the post-Day-Ahead Market Transmission Constraints list and the pre-Day-Ahead Market Transmission Constraints list made available by the CAISO pursuant to Section 6.5.3.3. The post-Day-Ahead Market Transmission Constraints list consists of the Transmission Constraints enforced or not enforced in the Day-Ahead Market conducted on any given day. The pre-Day-Ahead Market Transmission Constraints the CAISO plans to enforce or not enforce in the next day's Day-Ahead Market. These lists will identify and include definitions for all Transmission Constraints, including contingencies and nomograms. The definition of the Transmission Constraint includes the individual elements that constitute the Transmission Constraint. Both lists will each contain the same data elements and will provide: the flowgate constraints; transmission corridor constraints; the Nomogram constraints; and the list of Transmission Contingencies.

* * *

- Unaccounted For Energy (UFE)

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, and the total Measured 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.

* * *

- Unsecured Credit Limit

The level of credit established for a Market Participant that is not secured by any form of Financial Security, as provided for in Section 12.

- 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.

* * *

- [NOT USED]

APPENDIX B.4 PARTICIPATING LOAD AGREEMENT

* * *

ARTICLE IV

GENERAL TERMS AND CONDITIONS

4.3 **UDC Interruptible Load Programs.** Due to the CAISO's reliance on interruptible Loads to relieve System Emergencies and its contractual relationship with each UDC, the CAISO will not accept, and the Participating Load shall not submit, Bids from interruptible Loads which are subject to curtailment criteria established under existing retail tariffs, except under such conditions as may be specified in the CAISO Tariff.

4.6.1 **Submission of Bids and Self-provided Schedules**. When the Scheduling Coordinator on behalf of the Participating Load submits a Bid, the Participating Load will, by the operation of this Section 4.6.1, warrant to the CAISO that it has the capability to provide that service in accordance with the CAISO Tariff and that it will comply with CAISO Dispatch Instructions for the provision of the service in accordance with the CAISO Tariff.

* * *

APPENDIX B.6 MSA FOR METERED ENTITIES (MSA CAISOME)

* * *

ARTICLE I

DEFINITIONS AND INTERPRETATION

* * *

APPENDIX B.8 UTILITY DISTRIBUTION COMPANY OA (UDCOA)

* * *

ARTICLE III

GENERAL TERMS AND CONDITIONS

3.2 Agreement Subject to CAISO Tariff. This Operating Agreement shall be subject to the provisions of the CAISO Tariff which shall be deemed to be incorporated by reference herein, as the same may be changed or superseded from time to time pursuant to Section 15 of the CAISO Tariff. The Parties agree that they will comply with Section 4.4, and any other applicable provisions, of the CAISO Tariff.

3.4.1 Compliance with CAISO Specifications and CAISO Operating Procedures. The UDC will abide by and will perform all of the obligations under the CAISO Specifications and the CAISO Operating Procedures placed on UDCs in respect of all matters set forth therein as the same may be changed or superseded from time to time pursuant to the procedures set forth in Sections 22.11 and 22.4.3 of the CAISO Tariff. In the event of any conflict or dispute over interpretation, the CAISO Tariff shall, at all times, take precedence over the CAISO Specifications and CAISO Operating Procedures. The CAISO shall not implement any reliability requirements, operating requirements or performance standards that would impose increased costs on the UDC without giving due consideration to whether the benefits of such requirements or standards are sufficient to justify such increased costs. In any proceeding concerning the cost recovery by the UDC of capital and operation and maintenance costs incurred to comply with CAISO Specifications and Operating Procedures, the CAISO shall, at the request of the UDC, provide specific information regarding the nature of, and need for, the CAISO-imposed requirements or standards to enable the UDC to use this information in support of cost recovery through rates and tariffs.

3.6 Single Point of Contact. The CAISO and the UDC shall each provide a single point of contact on a 24-hour, 7-day basis for the exchange of operational procedures and information. The Parties agree to exchange operational contact information in a format to be provided by the CAISO and completed as of the effective date of this Operating Agreement. Each Party shall provide the other Party ten (10) calendar days advance notice of updates to its operational contact information as that information is expected to change. In the case of a UDC that is also a Participating TO, there may be only one single point of contact required and, in the reasonable discretion of the CAISO, duplicative reporting requirements and functions may be waived.

SCHEDULE 2

[NOT USED]

* * *

SCHEDULE 5

SYSTEM EMERGENCIES

The CAISO will notify the UDC's operational contact (Operations Shift Supervisor - Grid Control) of the emergency, including information regarding the cause, nature, extent, and potential duration of the emergency. The Operations Shift Supervisor will add any relevant data and will notify Distribution Operations. Distribution Operations will make the appropriate notifications within the UDC organization. The Operations Shift Supervisor and Distribution Control Shift Supervisor will then take such actions as are appropriate for the emergency.

The UDC will make requests for information from the CAISO regarding emergencies through the Operations Shift Supervisor, or the UDC Communication Coordinator may coordinate public information with the CAISO Communication Coordinator.

The UDC is required to estimate service restoration by geographic areas, and will use its call center and the media to communicate with customers during service interruptions. The UDC is also required to communicate the same information to appropriate state and local governmental entities. For transmission system caused outages the Operations Shift Supervisor will notify Distribution Operations Control Center of any information related to the outage such as cause, nature, extent, potential duration and customers affected.

Distribution Control and Grid Control Center logs, Electric Switching Orders and Energy Management System temporal data base will be used in preparation of outage reviews. These documents are defined as the chronological record of the operation of the activities which occur with the portion of the electrical system assigned to that control center. The log shall contain all pertinent information, including orders received and transmitted, relay operations, messages, clearances, accidents, trouble reports, daily switching program, etc.

The UDC will retain records in accordance with its record retention policy or practice, provided the records associated with this Operating Agreement are retained for a minimum of six years.

* * *

APPENDIX B.9 DSHBA OPERATING AGREEMENT (DSHBAOA)

* * *

3.4 Communication

The CAISO and the Host Balancing Authority shall each operate and maintain a 24-hour, 7-day control center with real-time scheduling and control functions. Appropriate control center staff will be provided by each Party who shall be responsible for operational communications and who shall have sufficient authority to commit and bind that Party. The CAISO and the Host Balancing Authority shall jointly develop communication procedures necessary to support scheduling and dispatch functions. The Parties agree to exchange operational contact information in a format to be provided by the CAISO and completed as of the effective date of this Agreement. Each Party shall provide the other Party ten (10) calendar days advance notice of updates to its operational contact information is expected to change.

* * *

11.4 Governing Law and Forum

Subject to Section 11.5, this Agreement shall be deemed to be a contract made under and for all purposes shall be governed by and construed in accordance with the laws of the State of California. The Parties irrevocably consent that any legal action or proceeding arising under or relating to this Agreement shall be brought in any of the following forums, as appropriate: a court of the State of California or any federal court of the United States of America located in the State of California or, where subject to its jurisdiction, before the Federal Energy Regulatory Commission. No provision of this Agreement shall be deemed to waive the right of any Party to protest, or challenge in any manner, whether this Agreement, or any action or proceeding arising under or relating to this Agreement, is subject to the jurisdiction of the Federal Energy Regulatory Commission.

SCHEDULE 1
[NOT USED]

* * *

APPENDIX B.10 SMALL UTILITY DISTRIBUTION CO. OA (SUDCOA)

* * *

ARTICLE III
GENERAL TERMS AND CONDITIONS

3.4 Agreement Subject to CAISO Tariff. Notwithstanding anything to the contrary herein, the Parties agree that they will comply with Section 4.11 of the CAISO Tariff, and any other applicable provisions of the CAISO Tariff specifically referenced in this Operating Agreement. This Operating Agreement shall be subject to such provisions of the CAISO Tariff, which shall be deemed to be incorporated to the extent referenced herein, as the same may be changed or superseded from time to time pursuant to Section 15 of the CAISO Tariff. Nothing in this Operating Agreement shall affect in any way the authority of the CAISO to unilaterally make application to FERC for a change in the CAISO Tariff under Section 205 of the Federal Power Act, nor shall anything in this Operating Agreement affect the right of either Party to file a complaint under Section 206 of the Federal Power Act regarding the CAISO Tariff.

* * *

3.6.1 Compliance with CAISO Specifications and CAISO Operating Procedures. The SUDC will abide by and will perform all of the obligations under the CAISO Specifications identified in Schedule 6 and CAISO Operating Procedures identified in Schedule 9 in respect of all matters set forth therein as the same may be changed or superseded from time to time pursuant to the procedures set forth in Sections 22.11 and 22.4.3 of the CAISO Tariff. In the event of any conflict or dispute over interpretation, those sections of the CAISO Tariff identified herein shall, at all times, take precedence over such CAISO Specifications and CAISO Operating Procedures. The CAISO shall not implement any reliability requirements, operating requirements or performance standards that would impose increased costs on the SUDC without giving due consideration to whether the benefits of such requirements or standards are sufficient to justify such increased costs. In any proceeding concerning the cost recovery by the SUDC of capital and operation and maintenance costs incurred to comply with CAISO Specifications and CAISO Operating Procedures, the CAISO shall to the extent practicable, at the request of the SUDC, provide specific information in a form that may be readily understood by the general public regarding the nature of, and need for, the CAISO-imposed requirements or standards to enable the SUDC to use this information in public hearings in support of cost recovery through rates and tariffs.

* * *

3.8 Single Point of Contact. The CAISO and the SUDC shall each provide a single point of contact for the exchange of operational procedures and information. The Parties agree to exchange operational contact information in a format to be provided by the CAISO and completed as of the effective date of this Operating Agreement. Each Party shall provide the other Party ten (10) calendar days advance notice of updates to its operational contact information as that information is expected to change.

SCHEDULE 3
[NOT USED]

* * *

APPENDIX B.14 PROXY DEMAND RESOURCE AGREEMENT

* * *

4.3 **Demand Response Provider Requirements.** The Demand Response Provider must register with the CAISO through the Demand Response System and comply with all terms of the CAISO Tariff. A Demand Response Provider that aggregates the demand response of customers for utilities that distribute: (1) over four million MWh in the previous fiscal year must certify to the CAISO that its participation is not prohibited by the Local Regulatory Authority; or (2) four million MWh or less in the previous fiscal year must certify to the CAISO that its participation is permitted by the Local Regulatory Authority applicable to Demand Response Providers, and that it has satisfied all applicable rules and regulations of the Local Regulatory Authority. The Demand Response Provider must certify to the CAISO that any required bilateral agreements between the Demand Response Provider and the Load Serving Entities or other agreements required by the Local Regulatory Authority are fully executed.

APPENDIX C LOCATIONAL MARGINAL PRICE

* * *

B. The System Marginal Energy Cost Component of LMP

The SMEC shall be the same for each location throughout the system. SMEC is the sensitivity of the power balance constraint at the optimal solution. The power balance constraint ensures that the physical law of conservation of Energy (the sum of Generation and imports equals the sum of Demand, including exports and Transmission Losses) is accounted for in the network solution. For the designated reference location the CAISO will utilize a distributed Load Reference Bus for which constituent PNodes are weighted using the Reference Bus distribution factors. The Load distributed Reference Bus distribution factors are based on the Load Distribution Factors at each PNode that represents cleared Load in the Integrated Forward Market or forecast Load for MPM-RRD, RUC, HASP and RTM. In the Integrated Forward Market, in the event that the market is not able to clear based on the use of a distributed load Reference Bus, the CAISO will use a distributed generation Reference Bus for which the constituent nodes and the weights are determined economically within the running of the Integrated Forward Market based on available economic bids. In the event that the CAISO employs a distributed generation Reference Bus, it will notify Market Participants of which Integrated Forward Market runs required the use of this backstop mechanism. A distributed Load Reference Bus will be used for MPM-RRD, RUC, HASP and RTM regardless of whether a distributed Generation Reference Bus were used in the corresponding Integrated Forward Market run. Once the Reference Bus is selected, the System Marginal Energy Cost is the cost of economically providing the next increment of Energy at the distributed Reference Bus, based on submitted Bids.

C. Marginal Congestion Component Calculation

The CAISO calculates the Marginal Costs of Congestion at each bus as a component of the bus-level LMP. The Marginal Cost of Congestion (MCCi) component of the LMP at bus i is calculated using the equation:

$$MCCi = -\left(\sum_{k=1}^{k} PTDFik * FSPk\right)$$

where:

- K is the number of thermal or interface Transmission Constraints.

PTDFik is the Power Transfer Distribution Factor for the generator at bus i on interface k which limits flows across that constraint when an increment of power is injected at bus i and an equivalent amount of power is withdrawn at the Reference Bus. The industry convention is to ignore the effect of losses in the determination of PTDFs.

- FSPk is the constraint Shadow Price on interface k and is equivalent to the reduction in system cost expressed in $/MWh that results from an increase of 1MW of the capacity on interface k.

The Shadow Price at a given binding Transmission Constraint is the value per MW of the next increment of generation that would flow across the constrained path by relaxing the binding Transmission Constraint. The PTDF of a PNode with respect to a transmission path (and direction on the path) measures the change in the power flow through the path (positive or negative, with respect to the designated direction on the path) as a result of an incremental injection at the Node, balanced by incremental change of Load at the Reference Bus.

* * *

G.1.1 Scheduling Point Prices

As described in Section 27.5.3, the CAISO's FNM includes a full model of the network topology of each IBAA. The CAISO will specify Resource IDs that associate Intertie Scheduling Point Bids and Schedules with supporting injection and withdrawal locations on the FNM. These Resource IDs may be specified by the CAISO based on the information available to it, or developed pursuant to a Market Efficiency Enhancement Agreement. Once these Resource IDs are established, the CAISO will determine Intertie Scheduling Point LMPs based on the injection and withdrawal locations associated with each Intertie Scheduling Point Bid and Schedule by the appropriate Resource ID. In calculating these LMPs the CAISO follows the provisions specified in Section 27.5.3 regarding the treatment of Transmission Constraints and losses on the IBAA network facilities. Unless otherwise required pursuant to an effective MEEA, the default pricing for all imports from the IBAA(s) to the CAISO Balancing Authority Area will be based on the SMUD/TID IBAA Import LMP and all exports to the IBAA(s) from the CAISO Balancing Authority Area will be based on the SMUD/TID IBAA Export LMP. The SMUD/TID IBAA Import LMP will be calculated based on modeling of supply resources that assumes all supply is from the Captain Jack substation as defined by WECC. The SMUD/TID IBAA Export LMP will be calculated based on the Sacramento Municipal Utility District hub that reflects Intertie distribution factors developed from a seasonal power flow base case study of the WECC region using an equivalencing technique that requires the Sacramento Municipal Utility District hub to be equivalenced to only the buses that comprise the aggregated set of load resources in the IBAA, with all generation also being retained at its buses within the IBAA. The resulting load distribution within each aggregated set of load resources within the IBAA defines the Intertie distribution factors for exports from the CAISO Balancing Authority Area.

* * *

APPENDIX E SUBMITTED ANCILLARY SERVICES DATA VERIFICATION
Verification of Submitted Data for Ancillary Services

6. Treatment of Equal Price Bids. The CAISO shall allow these Scheduling Coordinators to resubmit, at their own discretion, their Bid no later than two (2) hours the same day the original Bid was submitted. In the event identical prices still exist following resubmission of Bids, the CAISO 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 CAISO shall proportion participation in the Day-Ahead Schedule or HASP 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 CAISO.

* * *

APPENDIX F RATE SCHEDULES

Schedule 1
Grid Management Charge

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

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

* * *

8. The rate for the Settlements, Metering, and Client Relations Charge will be fixed at $1000.00 per month, per Scheduling Coordinator ID Code (SCID) with a non-zero invoice value where the non-zero value reflects market activity in the current Trading Month.

* * *

Part F –[NOT USED].

* * *

Schedule 3
High Voltage Access Charge and Wheeling Access Charge

* * *

1.1 Objectives.

* * *

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

* * *

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 CAISO a charge for transmission service on the High Voltage Transmission Facilities included in the CAISO Controlled Grid. The charge will be based on the High Voltage Access Charge applicable to the TAC Area in which the point of delivery is located and the applicable Transition Charge. A UDC or MSS Operator that is also a Participating TO shall pay, or receive payment of, if applicable, the difference between (i) the High Voltage Access Charge and Transition Charge applicable to its transactions as a UDC or MSS Operator; and (ii) the disbursement of High Voltage Access Charge revenues to which it is entitled pursuant to Section 26.1.3 of the CAISO Tariff. At the conclusion of the 10-year TAC Transition Period, the Transition Charge will cease to apply, and the HVAC will be based on the single CAISO Grid-wide rate.

* * *

5.1 The Access Charge consists of a High Voltage Access Charge (HVAC) that is based on a TAC Area component and a CAISO Grid-wide component, a Transition 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. At the conclusion of the 10-year TAC Transition Period, the Transition Charge will cease to apply, and the HVAC will be based on the single CAISO Grid-wide rate.

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. At the conclusion of the 10-year TAC Transition Period, the Transition Charge will cease to apply, and the HVAC will be based on the single CAISO Grid-wide rate. Accordingly, the requirement for each Participating TO to divide its HVTRR into new and existing components shall cease to apply.

* * *

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 CAISO 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 CAISO 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).

$$ETRRI = \Sigma\ ETRR_A * \%_I GW$$

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

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

* * *

5.9 After the completion of the TAC 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, and the provisions of this Section 5 of this Schedule 3 referring to the calculation and application of the TAC Transition Charge shall cease to apply.

* * *

7. Limitation.

(a) During each year of the TAC Transition Period described in this Schedule 3, the increase in the total payment responsibility applicable to Gross Loads in the PTO Service Territory of an Original Participating TO attributable to the total for the year of (i) the amount applicable for the Original Participating TO under Section 26.5 of the CAISO 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 CAISO'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. At the conclusion of the ten-year TAC Transition Period, the Transition Charge and the obligations set forth in this Section 7 of this Schedule 3 will cease to apply, and the HVAC will be based on the single CAISO Grid-wide rate.

(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).

* * *

8.2 For service provided by a Participating TO prior to the TAC 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 TAC 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 in the CAISO Market Invoice.

* * *

13.2 Updates to Low Voltage Access Charges. Unless otherwise agreed by the affected Participating TOs, a Non-Load-Serving Participating TO shall adjust its Low Voltage Access Charges and Low

Voltage Wheeling Access Charges (1) when necessary to reflect any new transmission addition directly connecting a Participating TO to the Low Voltage Transmission Facilities of the Non-Load-Serving Participating TO; (2) on the date FERC makes effective a change to the Low Voltage Transmission Revenue Requirement of the Non-Load-Serving Participating TO; and (3) on the date FERC makes effective a change to Gross Load of a Participating TO directly connected to the Non-Load-Serving Participating TO. Using the Low Voltage Transmission Revenue Requirement accepted or authorized by FERC, consistent with Section 9 of this Schedule 3, for the Non-Load-Serving Participating TO, the CAISO will recalculate the Low Voltage Access Charge applicable during such period. Revisions to the low voltage TRBA adjustment shall be made effective annually on January 1 based on the principal balance in the low voltage TRBA as of September 30 of the prior year and a forecast of Transmission Revenue Credits for the next year.

For service provided by a Non-Load-Serving Participating TO following the TAC Transition Date, any refund associated with a Non-Load-Serving Participating TO's Transmission Revenue Requirement that has been accepted by FERC, subject to refund, shall be provided as ordered by FERC. Such refund shall be invoiced in the CAISO Market Invoice.

If the Non-Load-Serving Participating TO withdraws one or more of its transmission facilities from the CAISO Operational Control in accordance with Section 3.4 of the Transmission Control Agreement, then the CAISO will no longer collect the TRR for that transmission facility through the CAISO's Access Charge effective upon the date the transmission facility is no longer under the Operational Control of the CAISO. The withdrawing Non-Load-Serving Participating TO shall be obligated to provide the CAISO 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 CAISO shall revise its transmission Access Charge to reflect the withdrawal of one or more transmission facilities from CAISO Operational Control.

* * *

APPENDIX G PRO FORMA RELIABILITY MUST-RUN CONTRACT
MUST-RUN SERVICE AGREEMENT

* * *

ARTICLE 1 DEFINITIONS

* * *

"Competitive Constraints Run" is defined in Appendix A to the CAISO Tariff.

* * *

"Forced Outage" means a reduction in Availability of a Unit for which sufficient notice is not given to allow the outage to be factored into CAISO's day-ahead or hour-ahead scheduling process.

ARTICLE 4 DISPATCH OF UNITS

4.1 CAISO's Right to Dispatch

* * *

(c) Except as needed for black start or voltage support required to meet local reliability needs, to meet operating criteria associated with the Potrero power plant, or as outlined below, CAISO may issue Dispatch Notices for Ancillary Services only if the available bids in Ancillary Service capacity markets do not provide sufficient capacity to meet CAISO's requirements.

(i) If the CAISO determines on a Trading Day that it needs additional Ancillary Service on that Trading Day, CAISO shall use the following procedures:

(A) CAISO shall communicate such needs to all Scheduling Coordinators as quickly as possible after such needs are identified.

(B) After completing (A), CAISO shall attempt to procure those additional Ancillary Services from the CAISO's Real-Time market (in the appropriate region if CAISO is procuring Ancillary Services on a regional basis) that have not closed, subject to the Bid Sufficiency Test described below.

(C) CAISO shall not issue a Dispatch Notice for Ancillary Services for any hour of the Trading Day before the earlier of (a) the time at which the real-time market for that hour closes or (b) if a Start-up would be required to provide the Ancillary Service, such earlier time as is necessary to comply with the applicable Start-up Lead Time and Ramping constraints on Schedule A.

* * *

4.6 Limitations on CAISO's Right to Dispatch

CAISO's Dispatch Notice may not request Owner to, and Owner shall not be obligated to:

* * *

(iv) Start-up a Unit unless the time between the delivery of the Dispatch Notice requesting such Start-up and the commencement of the applicable Requested Operation Period equals at least the Start-up Lead Time for the Unit and the Dispatch Notice provides sufficient time to satisfy the Ramping constraint of the Unit;

* * *

4.9 Test Dispatch Notices

(a) Availability Tests

* * *

(iii) The Test Dispatch Notice shall be marked "Availability Test Dispatch Notice." The Test Dispatch Notice shall specify a Requested Operation Period of four hours of continuous operations at the requested output plus any applicable Start-up Lead Time, time to satisfy Ramping constraints and time for Shutdown (or for hydroelectric Units the time sufficient water is available, if that is less).

* * *

ARTICLE 5 DELIVERY OF ENERGY AND ANCILLARY SERVICES BY OWNER

5.1 Owner's Delivery of Energy and Ancillary Services

(a) Subject to the limits in this Agreement, and subject to the CAISO's Real-Time Dispatch instructions whether flagged as an RMR Dispatch or not, Owner shall provide service from the Units and Deliver the Requested MWh or Requested Ancillary Services in accordance with each Dispatch Notice. To the maximum extent practical, and except for regulation, Owner shall Deliver at each moment of each hour during the Requested Operation Period not less than the Requested MW or Requested Ancillary Services. If Owner has disputed a Dispatch Notice under Section 4.6 (i) (Minimum Load) (ii) (Minimum Run Time) (iii) (Minimum

Off Time) (iv) (Start-up Lead Time and Ramping constraint), or (v) (Unit Availability Limit) and such dispute is not resolved prior to the time for delivery, Owner will use reasonable efforts to comply with the Dispatch Notice, but shall not be liable to CAISO if it is unable to do so and Owner prevails in the dispute.

* * *

5.2 Substitution of Market Transactions for Dispatch Notices

(b) Owner shall give notice of its intent to substitute a Market Transaction through the submission of bids in the CAISO's Markets. Any dispatch level that clears the Competitive Constraints Run of the MPM-RRD process through the submission of Economic Bids or Self-Schedules, and is reflected in the Day-Ahead Schedule or Real-Time Dispatch, shall be deemed a Market Transaction.

* * *

ARTICLE 6 MARKET TRANSACTIONS

6.1 Right To Engage In Market Transactions

* * *

(b) If CAISO issues a Dispatch Notice for a Unit operating under Condition 2, Owner shall submit bids in succeeding available Energy and Ancillary Services markets for the Requested Operation Period in accordance with the following requirements:

* * *

(v) Owner shall not bid Energy or Ancillary Services in excess of the quantities the Unit can provide during the Requested Operation Period given the Unit's ramp rates, Ramping constraints and any other applicable operating limitations, with due allowance for a Unit's ability to change output during the Requested Operation Period.

APPENDIX L METHOD TO ASSESS AVAILABLE TRANSFER CAPABILITY

* * *

L.1.1 Available Transfer Capability (ATC) is a measure of the transfer capability in the physical transmission network resulting from system conditions and that remains available for further commercial activity over and above already committed uses.

ATC is defined as the Total Transfer Capability (TTC) less applicable operating Transmission Constraints due to system conditions and Outages (i.e., OTC), less the Transmission Reliability Margin (TRM) (which value is set at zero), less the sum of any unused existing transmission commitments (ETComm) (i.e., transmission rights capacity for ETC or TOR), less the Capacity Benefit Margin (CBM) (which value is set at zero), less the Scheduled Net Energy from Imports/Exports, less Ancillary Service capacity from Imports.

* * *

L.1.3 Operating Transfer Capability (OTC) is the TTC reduced by any operational Transmission Constraints caused by seasonal derates or Outages. CAISO Regional Transmission Engineers (RTE) determine OTC through studies using computer modeling.

* * *

L.1.6 **Transmission Reliability Margin (TRM)** is that amount of transmission transfer capability necessary reserved in the Day-Ahead Market (DAM) to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. This DAM implementation avoids Real-Time Schedule curtailments that would otherwise be necessary due to:

- Demand Forecast error
- Anticipated uncertainty in transmission system topology
- Unscheduled flow
- Simultaneous path interactions
- Variations in Generation Dispatch
- Operating Reserve actions

The level of TRM for each Transmission Interface will be determined by CAISO Regional Transmission Engineers (RTE).

The CAISO does not use TRMs. The TRM value is set at zero.

L.1.7 **Capacity Benefit Margin (CBM)** is that amount of transmission transfer capability reserved for Load Serving Entities (LSEs) to ensure access to Generation from interconnected systems to meet generation reliability requirements. In the Day-Ahead Market, CBM may be used to provide reliable delivery of Energy to CAISO Balancing Authority Area Loads and to meet CAISO responsibility for resource reliability requirements in Real-Time. The purpose of this DAM implementation is to avoid Real-Time Schedule curtailments and firm Load interruptions that would otherwise be necessary. CBM may be used to reestablish Operating Reserves. CBM is not available for non-firm transmission in the CAISO Balancing Authority Area. CBM may be used only after:

- all non-firm sales have been terminated,
- direct-control Load management has been implemented,
- customer interruptible Demands have been interrupted,
- if the LSE calling for its use is experiencing a Generation deficiency and its transmission service provider is also experiencing transmission Constraints relative to imports of Energy on its transmission system.

The level of CBM for each Transmission Interface is determined by the amount of estimated capacity needed to serve firm Load and provide Operating Reserves based on historical, scheduled, and/or forecast data using the following equation to set the maximum CBM:

CBM = (Demand + Reserves) - Resources

Where:

- Demand = forecasted area Demand
- Reserves = reserve requirements
- Resources = internal area resources plus resources available on other Transmission Interfaces

The CAISO does not use CBMs. The CBM value is set at zero.

L.2 ATC Algorithm

The ATC algorithm is a calculation used to determine the transfer capability remaining in the physical transmission network and available for further commercial activity over and above already committed uses. The CAISO posts the ATC values in megawatts (MW) to OASIS in conjunction with the closing events for the Day-Ahead Market and HASP Real-Time Market process.

The following OASIS ATC algorithms are used to implement the CAISO ATC calculation for the ATC rated path (Transmission Interface):

OTC = TTC – CBM – TRM - Operating Constraints

ATC Calculation For Imports:
ATC = OTC – AS from Imports- Net Energy Flow - Hourly Unused TR Capacity.

ATC Calculation For Exports:
ATC = OTC – Net Energy Flow - Hourly Unused TR Capacity.

ATC Calculation For Internal Paths 15 and 26:
ATC = OTC – Net Energy Flow

The specific data points used in the ATC calculation are each described in the following table.

ATC	ATC MW	Available Transfer Capability, in MW, per Transmission Interface and path direction.
Hourly Unused TR Capacity	USAGE_MW	The sum of any unscheduled existing transmission commitments (scheduled transmission rights capacity for ETC or TOR), in MW, per path direction.
Scheduled Net Energy from Imports/Exports (Net Energy Flow)	ENE IMPORT MW	Total hourly net Energy flow for a specified Transmission Interface.
AS from Imports	AS IMPORT MW	Ancillary Services scheduled, in MW, as imports over a specified Transmission Interface.
OTC	OTC MW	Hourly Operating Transfer Capability of a specified Transmission Interface, per path direction, with consideration given to known Constraints and operating limitations.
Transmission Constraint	Constraint MW	Hourly Transmission Constraints, in MW, for a specific Transmission Interface and path direction.
CBM	CBM MW	Hourly Capacity Benefit Margin, in MW, for a specified Transmission Interface, per Path Direction.
TRM	TRM MW	Hourly Transmission Reliability Margin, in MW, for a specified Transmission Interface, per path direction.
TTC	TTC MW	Hourly Total Transfer Capability, in MW, of a specified Transmission Interface, per path direction.

The links to the CAISO Website where the actual ATC mathematical algorithms and other ATC calculational information are located are as follows:

Operating Procedures – Transmission
http://www.caiso.com/thegrid/operations/opsdoc/transmon/index.html

Operating Procedure - Total Transfer Capability Methodology
http://www.caiso.com/1bfe/1bfe98134fa0.pdf

Operating Procedure - System Operating Methodology
http://www.caiso.com/1c13/1c1390d420810.pdf

Business Practice Manual for Market Operations
https://bpm.caiso.com/bpm/bpm/version/000000000000005

OASIS – Transmission Information
http://oasis.caiso.com/mrtu-oasis

* * *

L.4 TTC – OTC Determination

All transfer capabilities are developed to ensure that power flows are within their respective operating limits, both pre-Contingency and post-Contingency. Operating limits are developed based on thermal, voltage and stability concerns according to industry reliability criteria (WECC/NERC) for transmission paths. The process for developing TTC or OTC is the same with the exception of inclusion or exclusion of operating Constraints based on system conditions being studied. Accordingly, further description of the process to determine either OTC or TTC will refer only to TTC.

* * *

APPENDIX M PROCEDURES FOR ADDRESSING PARALLEL FLOWS

The North American Electric Reliability Corporation's (NERC) Qualified Path Unscheduled Flow Relief for the Western Electricity Coordinating Council (WECC), Reliability Standard WECC-IRO-STD-006-0 filed by NERC in FERC Docket No. RR07-11-000 on March 26, 2007, and approved by FERC on June 8, 2007, and any amendments thereto, are hereby incorporated and made part of this CAISO Tariff. See www.nerc.com for the current version of the NERC's Qualified Path Unscheduled Flow Relief Procedures for WECC.

* * *

APPENDIX O CAISO MARKET SURVEILLANCE COMMITTEE

* * *

9.4 Members of the MSC shall not engage in any market transactions other than in the performance of their duties under the CAISO Tariff.

APPENDIX P CAISO DEPARTMENT OF MARKET MONITORING

* * *

5 Duties of Market Monitor

* * *

5.1.7 Where the CAISO disagrees with DMM's recommendation pursuant to Section 5.1 of this Appendix P or DMM disagrees with a proposed market rule, tariff, or market design change, CAISO shall notify the FERC of such disagreement. Such notification shall be made in writing to FERC's Director of the Office of Energy Market Regulation.

* * *

5.5 Prohibition on Tariff Administration and Market Mitigation – DMM shall not participate in the administration of the CAISO Tariff or conduct prospective market mitigation.

5.5.1 For the purposes of Section 5.5 of this Appendix P, the term "prospective market mitigation" shall have the same meaning as provided in FERC Order No. 719, P 375.

* * *

5.5.3 DMM may provide the inputs required for CAISO to conduct any prospective mitigation that is otherwise permitted under this CAISO Tariff. Such inputs may include, but are not limited to, Default Energy Bids, identification of competitive Transmission Constraints, and cost calculations.

* * *

8. Information Sharing

* * *

8.1.4 DMM shall not provide any requested information or data that would impinge on FERC's confidentiality rules regarding referrals to FERC pursuant to Sections 11 or 12 of this Appendix P.

8.5 Collection and Dissemination of Information Specific to a Market Participant
8.5.1 DMM may request that Market Participants or other entities whose activities may affect the operation of the CAISO Markets submit any information or data determined by DMM to be potentially relevant. This data will be subject to due safeguards to protect confidential and commercially sensitive data. Failures by Market Participants to provide such data shall be treated under Section 37 of the CAISO Tariff. In the event of failures by other entities to provide such data, the CAISO 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 CAISO Markets or termination of any relevant CAISO agreements or certifications. Before any such action is taken, the CAISO Market Participant shall be provided the opportunity to respond in writing as to the reason for the alleged failure.

* * *

8.6 Information related to the Transmission Planning Process in accordance with Section 24 of the CAISO Tariff the release of which DMM determines may harm competitive markets shall be deemed confidential.

* * *

11. Protocol on Referrals of Investigations to the Office of Enforcement.
11.1 DMM shall make a non-public referral to FERC in all instances where DMM has reason to believe that a Market Violation has occurred. DMM's non-public referral shall provide sufficient credible information to warrant further investigation by FERC. Once DMM has obtained sufficient credible information to warrant referral to FERC, DMM shall immediately refer the matter to FERC and desist from independent action related to the alleged Market Violation. DMM may, however, continue to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market

Violations. DMM shall respond to requests from FERC for any additional information in connection with the alleged Market Violation it has referred.

* * *

11.1.3 Section 11.1 of this Appendix P notwithstanding, DMM may, but need not, refer to FERC a suspected violation of the following provisions of Section 37 of this CAISO Tariff: 37.2.1; 37.2.2; 37.2.4; 37.3.1; 37.4.1, 37.4.2; 37.4.3; 37.5.2; 37.6.1; 37.6.2; and 37.6.3.

11.2 All referrals to FERC of alleged Market Violations are to be in writing, whether transmitted electronically or by fax, mail, or courier. DMM may alert FERC orally in advance of the written referral.

11.3 The referral is to be addressed to FERC's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

* * *

11.4.7 Any other information DMM believes is relevant and may be helpful to FERC.

11.5 Following a referral to FERC, DMM is to continue to notify and inform FERC of any information that DMM learns of that may be related to the referral but DMM shall not undertake any investigative steps regarding the referral except at the express direction of FERC or FERC Staff.

12 Protocol on Referrals of Perceived Market Design Flaws and Recommended Tariff Changes to the Office of Energy Market Regulation.

12.1 DMM is to make a referral to FERC in all instances where it has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. DMM must limit distribution of its identifications and recommendations to CAISO, the CAISO Governing Board, and to FERC in the event it believes broader dissemination could lead to exploitation of the market design flaw, with an explanation of why further dissemination should be avoided at that time.

12.2 All referrals to FERC relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically or by fax, mail, or courier. DMM may alert FERC orally in advance of the written referral.

12.3 The referral should be addressed to FERC's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

* * *

12.4.4 Any other information DMM believes is relevant and may be helpful to FERC.

12.5 Following a referral to FERC, DMM is to continue to notify and inform FERC of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by DMM to CAISO, stakeholders, Market Participants or state commissions regarding the perceived design flaw, and any actions taken by CAISO regarding the perceived design flaw.

APPENDIX Q ELIGIBLE INTERMITTENT RESOURCES PROTOCOL (EIRP)

* * *

4.1 Hour-Ahead Forecast

The CAISO shall develop expert, independent hourly forecasts of Energy generation for each Participating Intermittent Resource. A forecast shall be published each hour for each of the next seven operating hours. Other forecasts, including a Day-Ahead forecast, may be developed at the CAISO's discretion. The Scheduling Coordinator representing the Participating Intermittent Resource must use the hour-ahead forecast that is available thirty minutes prior to the deadline for submitting the HASP/RTM Bids. The CAISO shall use best efforts to provide reliable and timely forecasts. However, if the CAISO fails to deliver the hour-ahead forecast to the Scheduling Coordinator prior to fifteen minutes before the deadline for submitting HASP/RTM Bids, then the hour-ahead forecast shall be the most recent Energy forecast provided by the CAISO to the Scheduling Coordinator for the operating hour for which Bids are next due.

4.2 [NOT USED]

* * *

APPENDIX U LARGE GENERATOR INTERCONNECTION PROCEDURES

* * *

11.3 Execution And Filing

At the time that the Interconnection Customer either returns the executed LGIA or requests the filing of an unexecuted LGIA as specified below, the Interconnection Customer shall provide the applicable Participating TO(s) and CAISO (A) reasonable evidence of continued Site Control or (B) posting to the applicable Participating TO(s) of $250,000, non-refundable additional security, which shall be applied toward future construction costs. At the same time, the Interconnection Customer also shall provide reasonable evidence that one or more of the following milestones in the development of the Large Generating Facility, at the Interconnection Customer election, has been achieved: (i) the execution of a contract for the supply or transportation of fuel to the Large Generating Facility; (ii) the execution of a contract for the supply of cooling water to the Large Generating Facility; (iii) execution of a contract for the engineering for, procurement of major equipment for, or construction of, the Large Generating Facility; (iv) execution of a contract for the sale of electric energy or capacity from the Large Generating Facility; or (v) application for an air, water, or land use permit.

The Interconnection Customer shall either: (i) execute the appropriate number of originals of the tendered LGIA as specified in the directions provided by the CAISO and return them to the CAISO, as directed, for completion of the execution process; or (ii) request in writing that the applicable Participating TO(s) and CAISO file with FERC an LGIA in unexecuted form. The LGIA shall be considered executed as of the date that all Parties have signed the LGIA. As soon as practicable, but not later than ten (10) Business Days after receiving either the executed originals of the tendered LGIA (if it does not conform with a FERC-approved standard form of interconnection agreement) or the request to file an unexecuted LGIA, the applicable Participating TO(s) and CAISO shall file the LGIA with FERC, as necessary, together with an explanation of any matters as to which the Interconnection Customer and the applicable Participating TO(s) or CAISO disagree and support for the costs that the applicable Participating TO(s) propose to charge to the Interconnection Customer under the LGIA. An unexecuted LGIA should contain terms and conditions deemed appropriate by the applicable Participating TO(s) and CAISO for the Interconnection Request. If the Parties agree to proceed with design, procurement, and construction of facilities and upgrades under the agreed-upon terms of the unexecuted LGIA, they may proceed pending FERC action.

* * *

APPENDIX 3 INTERCONNECTION FEASIBILITY STUDY AGREEMENT

THIS AGREEMENT is made and entered into this day of , 20___ by and between _____________, a _______________ organized and existing under the laws of the State of , ("Interconnection Customer") and the California Independent System Operator Corporation, a California nonprofit public benefit corporation existing under the laws of the State of California, ("CAISO"). The Interconnection Customer and theCAISO each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by the Interconnection Customer dated[1]; and

[footnote 1: This recital to be omitted if the Interconnection Customer has elected to forego the Interconnection Feasibility Study.]

WHEREAS, the Interconnection Customer desires to interconnect the Large Generating Facility with the CAISO Controlled Grid; and

WHEREAS, the Interconnection Customer has requested the CAISO to conduct or cause to be performed an Interconnection Feasibility Study to assess the feasibility of interconnecting the proposed Large Generating Facility.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in the CAISO's FERC-approved Standard Large Generation Interconnection Procedures ("LGIP") or the Master Definitions Supplement, Appendix A to the CAISO Tariff, as applicable.

2.0 The Interconnection Customer elects and the CAISO shall conduct or cause to be performed an Interconnection Feasibility Study consistent with the LGIP in accordance with the CAISO Tariff.

3.0 The scope of the Interconnection Feasibility Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection Feasibility Study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the Scoping Meeting. The CAISO reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Feasibility Study and as designated in accordance with Section 3.5.4 of the LGIP. If, after the designation of the Point of Interconnection pursuant to Section 3.5.4 of the LGIP, the Interconnection Customer modifies its Interconnection Request pursuant to Section 4.4 of the LGIP, the time to complete the Interconnection Feasibility Study may be extended.

5.0 The Interconnection Feasibility Study report shall provide the following information:

- preliminary identification of any circuit breaker short circuit capability limits exceeded on the Participating TO's electric system or the CAISO Controlled Grid as a result of the interconnection;

- preliminary identification of any thermal overload or voltage limit violations on the Participating TO's electric system or the CAISO Controlled Grid resulting from the interconnection;

- preliminary description and non-binding good faith estimate of cost and cost responsibility for and time for construction of the Participating TO's facilities required to interconnect the Large Generating Facility to the Participating TO's electric system or the CAISO Controlled Grid and to address the identified short circuit and power flow issues;

- preliminary identification of financial impacts, if any, on Local Furnishing Bonds; and

- expected results in the Interconnection System Impact Study.

* * *

APPENDIX V LARGE GENERATOR INTERCONNECTION AGREEMENT

STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT (LGIA)

[INTERCONNECTION CUSTOMER]

[PARTICIPATING TO]

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

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Appendix H Interconnection Requirements for a Wind Generating Plant

STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

[INTERCONNECTION CUSTOMER]

[PARTICIPATING TO]

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

* * *

ARTICLE 1. DEFINITIONS

* * *

NERC shall mean the North American Electric Reliability Corporation or its successor organization.

ARTICLE 5. FACILITIES ENGINEERING, PROCUREMENT, AND CONSTRUCTION

* * *

5.4 Power System Stabilizers. The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council and in accordance with the provisions of Section 4.6.5.1 of the CAISO Tariff. The CAISO reserves the right to establish reasonable minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, the Interconnection Customer shall immediately notify the CAISO and the Participating TO and restore the Power System Stabilizers to operation as soon as possible. The CAISO shall have the right to order the reduction in output or disconnection of the Large Generating Facility if the reliability of the CAISO Controlled Grid would be adversely affected as a result of improperly tuned Power System Stabilizers. The requirements of this Article 5.4 shall not apply to wind generators of the induction type.

* * *

ARTICLE 9. OPERATIONS

9.1 General. Each Party shall comply with the Applicable Reliability Council requirements. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

* * *

9.6.2.1 Governors and Regulators. Whenever an Electric Generating Unit is operated in parallel with the CAISO Controlled Grid and the speed governors (if installed on the Electric Generating Unit pursuant to Good Utility Practice) and voltage regulators are capable of operation, the Interconnection Customer shall operate the Electric Generating Unit with its speed governors and voltage regulators in automatic operation. If the Electric Generating Unit's speed governors and voltage regulators are not capable of such automatic operation, the Interconnection Customer shall immediately notify the CAISO and the Participating TO and ensure that the Electric Generating Unit operates as specified in Article 9.6.2 through manual operation and that such Electric Generating Unit's reactive power production or absorption (measured in MVARs) are within the design capability of the Electric Generating Unit(s) and steady state stability limits. The Interconnection Customer shall restore the speed governors and voltage regulators to automatic operation as soon as possible. If the Large Generating Facility's speed governors and voltage regulators are improperly tuned or malfunctioning, the CAISO shall have the right to order the reduction in output or disconnection of the Large Generating Facility if the reliability of the CAISO Controlled Grid would be adversely affected. The Interconnection Customer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the CAISO Controlled Grid or trip any Electric Generating Unit comprising the Large Generating Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Balancing Authority Area on a comparable basis.

* * *

ARTICLE 30. MISCELLANEOUS

* * *

30.11 Reservation of Rights. The CAISO and Participating TO shall each have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following Articles of this LGIA and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these Articles:

Recitals, 1, 2.1, 2.2, 2.3, 2.4, 2.6, 3.1, 3.3, 4.1, 4.2, 4.3, 4.4, 5 preamble, 5.4, 5.7, 5.8, 5.9, 5.12, 5.13, 5.18, 5.19.1, 7.1, 7.2, 8, 9.1, 9.2, 9.3, 9.5, 9.6, 9.7, 9.8, 9.10, 10.3, 11.4, 12.1, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24.3, 24.4, 25.1, 25.2, 25.3 (excluding subparts), 25.4.2, 26, 28, 29, 30, Appendix D, Appendix F, and any other Article not reserved exclusively to the Participating TO or the CAISO below.

The Participating TO shall have the exclusive right to make a unilateral filing with FERC to modify this LGIA pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following Articles of this LGIA and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these Articles:

2.5 , 5.1, 5.2, 5.3, 5.5, 5.6, 5.10, 5.11, 5.14, 5.15, 5.16, 5.17, 5.19 (excluding 5.19.1), 6, 7.3, 9.4, 9.9, 10.1, 10.2, 10.4, 10.5, 11.1, 11.2, 11.3, 11.5, 12.2, 12.3, 12.4, 24.1, 24.2, 25.3.1, 25.4.1, 25.5 (excluding 25.5.1), 27 (excluding preamble), Appendix A, Appendix B, Appendix C, and Appendix E.

The CAISO shall have the exclusive right to make a unilateral filing with FERC to modify this LGIA pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following Articles of this LGIA and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these Articles:

3.2 , 4.5, 11.6, 25.3.2, 25.5.1, and 27 preamble.

The Interconnection Customer, the CAISO, and the Participating TO shall have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this LGIA shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

* * *

IN WITNESS WHEREOF, the Parties have executed this LGIA in multiple originals, each of which shall constitute and be an original effective agreement among the Parties.

[Insert name of Participating TO]

By:

Title:

Date:

California Independent System Operator Corporation

By:

Title:

Date:

[Insert name of Interconnection Customer]

By:

Title:

Date:

Appendices to LGIA

Appendix A Interconnection Facilities, Network Upgrades and Distribution Upgrades

Appendix B Milestones

Appendix C Interconnection Details

Appendix D Security Arrangements Details

Appendix E Commercial Operation Date

Appendix F Addresses for Delivery of Notices and Billings

Appendix G [NOT USED]

Appendix H Interconnection Requirements for a Wind Generating Plant

* * *

APPENDIX G [NOT USED]

* * *

APPENDIX X DYNAMIC SCHEDULING PROTOCOL (DSP)

* * *

8.4 All Dynamic Schedules and delivered Energy shall be subject to the standard CAISO Transmission Loss calculation associated with the particular Scheduling Point.

* * *

APPENDIX Y GIP FOR INTERCONNECTION REQUESTS

* * *

6.5.2.1 The On-Peak Deliverability Assessment.

The CAISO, in coordination with the applicable Participating TO(s), shall perform an On-Peak Deliverability Assessment for Interconnection Customers selecting Full Capacity Deliverability Status in their Interconnection Requests. The On-Peak Deliverability Assessment shall determine the Interconnection Customer's Generating Facility's ability to deliver its Energy to the CAISO Controlled Grid under peak load conditions, and identify preliminary Delivery Network Upgrades required to provide the Generating Facility with Full Capacity Deliverability Status. The preliminary Delivery Network Upgrades identified by the On-Peak Deliverability Assessment will be used to establish the maximum cost responsibility for Delivery Network Upgrades for each Interconnection Customer selecting Full Capacity Deliverability Status. Deliverability of a new Generating Facility will be assessed on the same basis as all other existing resources interconnected to the CAISO Controlled Grid.

The On-Peak Deliverability Assessment will identify the Network Upgrades that are required to enable the Generating Facility of each Interconnection Customer requesting Full Capacity Deliverability Status to meet the requirements for deliverability. Deliverability requires that the Generating Facility Capacity, as set forth in the Interconnection Request, can be delivered to the aggregate of Load on the CAISO Controlled Grid, consistent with Reliability Criteria, under CAISO Controlled Grid peak load and Contingency conditions, and assuming the aggregate output of existing Generating Facilities with established Net Qualifying Capacity values and other Generating Facilities in the Interconnection Study Cycle seeking Full Capacity Deliverability Status identified within the On-Peak Deliverability Assessment based on the effect of Transmission Constraints.

The On-Peak Deliverability Assessment will further perform an analysis to estimate the MW of deliverable generation capacity for the individual or Group Study if the highest cost Delivery Network Upgrade component were removed from the preliminary Delivery Network Upgrade plan, or, at the CAISO's sole discretion, if any other identified Delivery Network Upgrade component(s) were removed from the preliminary Delivery Network Upgrade plan. This information is provided to allow Interconnection Customers to address at the Results Meeting potential modifications under GIP Section 6.9.2 or change the Interconnection Request's Full Capacity Deliverability Status for purposes of financing under GIP Section 12.3.1.

The methodology for the On-Peak Deliverability Assessment will be published on the CAISO Website or, when effective, included in a CAISO Business Practice Manual. The On-Peak Deliverability Assessment does not convey any right to deliver electricity to any specific customer or Delivery Point.

The cost of all Delivery Network Upgrades identified in the On-Peak Deliverability Assessment as part of a Phase I Interconnection Study shall be estimated in accordance with GIP Section 6.4. The estimated costs of Delivery Network Upgrades identified in the On-Peak Deliverability Assessment shall be assigned to all Interconnection Requests selecting Full Capacity Deliverability Status based on the flow impact of each such Generating Facility on the Delivery Network Upgrades as determined by the Generation distribution factor methodology set forth in the On-Peak Deliverability Assessment methodology.

* * *

APPENDIX Z LGIA FOR INTERCONNECTION REQUESTS PROCESS UNDER THE GIP

LARGE GENERATOR INTERCONNECTION AGREEMENT (LGIA)

[INTERCONNECTION CUSTOMER]

[PARTICIPATING TO]

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

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* * *

ARTICLE 1. DEFINITIONS

* * *

NERC shall mean the North American Electric Reliability Corporation or its successor organization.

ARTICLE 5. FACILITIES ENGINEERING, PROCUREMENT, AND CONSTRUCTION

* * *

5.16 Suspension. The Interconnection Customer reserves the right, upon written notice to the Participating TO and the CAISO, to suspend at any time all work associated with the construction and installation of the Participating TO's Interconnection Facilities, Network Upgrades, and/or Distribution Upgrades required under this LGIA, other than Network Upgrades identified in the Phase II Interconnection Study as common to multiple Generating Facilities, with the condition that the Participating TO's electrical system and the CAISO Controlled Grid shall be left in a safe and reliable condition in accordance with Good Utility Practice and the Participating TO's safety and reliability criteria and the CAISO's Applicable Reliability Standards. In such event, the Interconnection Customer shall be responsible for all reasonable and necessary costs which the Participating TO (i) has incurred pursuant to this LGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Participating TO's electric system during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which the Participating TO cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, the Participating TO shall obtain Interconnection Customer's authorization to do so.

The Participating TO shall invoice the Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work required under this LGIA pursuant to this Article 5.16, and has not requested the Participating TO to recommence the work or has not itself recommenced work required under this LGIA in time to ensure that the new projected Commercial Operation Date for the full Generating Facility Capacity of the Large Generating Facility is no more than three (3) years from the Commercial Operation Date identified in Appendix B hereto, this LGIA shall be deemed terminated and the Interconnection Customer's responsibility for costs will be determined in accordance with Article 2.4. The suspension period shall begin on the date the suspension is requested, or the date of the written notice to the Participating TO and the CAISO, if no effective date is specified.

* * *

APPENDIX BB STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

Standard Large Generator Interconnection Agreement

for Interconnection Requests in a Serial Study Group that are tendered or execute a Large Generator Interconnection Agreement on or after July 3, 2010

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* * *

ARTICLE 1. DEFINITIONS

* * *

NERC shall mean the North American Electric Reliability Corporation or its successor organization.

* * *

ARTICLE 5. INTERCONNECTION FACILITIES ENGINEERING, PROCUREMENT, AND CONSTRUCTION

* * *

5.4 **Power System Stabilizers**. The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council and in accordance with the provisions of Section 4.6.5.1 of the CAISO Tariff. The CAISO reserves the right to establish reasonable minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, the Interconnection Customer shall immediately notify the CAISO and the Participating TO and restore the Power System Stabilizers to operation as soon as possible. The CAISO shall have the right to order the reduction in output or disconnection of the Large Generating Facility if the reliability of the CAISO Controlled Grid would be adversely affected as a result of improperly tuned Power System Stabilizers. The requirements of this Article 5.4 shall apply to Asynchronous Generating Facilities in accordance with Appendix H.

* * *

ARTICLE 9. OPERATIONS

9.1 General. Each Party shall comply with the Applicable Reliability Council requirements. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

* * *

9.6.2.1 Governors and Regulators. Whenever an Electric Generating Unit is operated in parallel with the CAISO Controlled Grid and the speed governors (if installed on the Electric Generating Unit pursuant to Good Utility Practice) and voltage regulators are capable of operation, the Interconnection Customer shall operate the Electric Generating Unit with its speed governors and voltage regulators in automatic operation. If the Electric Generating Unit's speed governors and voltage regulators are not capable of such automatic operation, the Interconnection Customer shall immediately notify the CAISO and the Participating TO and ensure that the Electric Generating Unit operates as specified in Article 9.6.2 through manual operation and that such Electric Generating Unit's reactive power production or absorption (measured in MVARs) are within the design capability of the Electric Generating Unit(s) and steady state stability limits. The Interconnection Customer shall restore the speed governors and voltage regulators to automatic operation as soon as possible. If the Large Generating Facility's speed governors and voltage regulators are improperly tuned or malfunctioning, the CAISO shall have the right to order the reduction in output or disconnection of the Large Generating Facility if the reliability of the CAISO Controlled Grid would be adversely affected. The Interconnection Customer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the CAISO Controlled Grid or trip any Electric Generating Unit comprising the Large Generating Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Balancing Authority Area on a comparable basis.

* * *

ARTICLE 30. MISCELLANEOUS

* * *

30.11 Reservation of Rights. The CAISO and Participating TO shall each have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following Articles of this LGIA and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these Articles:

> Recitals, 1, 2.1, 2.2, 2.3, 2.4, 2.6, 3.1, 3.3, 4.1, 4.2, 4.3, 4.4, 5 preamble, 5.4, 5.7, 5.8, 5.9, 5.12, 5.13, 5.18, 5.19.1, 7.1, 7.2, 8, 9.1, 9.2, 9.3, 9.5, 9.6, 9.7, 9.8, 9.10, 10.3, 11.4, 12.1, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24.3, 24.4, 25.1, 25.2, 25.3 (excluding subparts), 25.4.2, 26, 28, 29, 30, Appendix D, Appendix F, and any other Article not reserved exclusively to the Participating TO or the CAISO below.

The Participating TO shall have the exclusive right to make a unilateral filing with FERC to modify this LGIA pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following Articles of this LGIA and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these Articles:

> 2.5, 5.1, 5.2, 5.3, 5.5, 5.6, 5.10, 5.11, 5.14, 5.15, 5.16, 5.17, 5.19 (excluding 5.19.1), 6, 7.3, 9.4, 9.9, 10.1, 10.2, 10.4, 10.5, 11.1, 11.2, 11.3, 11.5, 12.2, 12.3, 12.4, 24.1, 24.2, 25.3.1, 25.4.1, 25.5 (excluding 25.5.1), 27 (excluding preamble), Appendix A, Appendix B, Appendix C, and Appendix E.

The CAISO shall have the exclusive right to make a unilateral filing with FERC to modify this LGIA pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following Articles of this LGIA and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these Articles:

> 3.2, 4.5, 11.6, 25.3.2, 25.5.1, and 27 preamble.

The Interconnection Customer, the CAISO, and the Participating TO shall have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this LGIA shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

* * *

IN WITNESS WHEREOF, the Parties have executed this LGIA in multiple originals, each of which shall constitute and be an original effective agreement among the Parties.

[Insert name of Participating TO]

By: ______________________

Title: ______________________

Date:

California Independent System Operator Corporation

By: ______________________

Title: ______________________

Date:

[Insert name of Interconnection Customer]

By: ______________________

Title: ______________________

Date:

Appendices to LGIA

Appendix A Interconnection Facilities, Network Upgrades and Distribution Upgrades

Appendix B Milestones

Appendix C Interconnection Details

Appendix D Security Arrangements Details

Appendix E Commercial Operation Date

Appendix F Addresses for Delivery of Notices and Billings

Appendix G [NOT USED]

Appendix H Interconnection Requirements for a Wind Generating Plant

* * *

APPENDIX G [NOT USED]

APPENDIX CC LARGE GENERATOR INTERCONNECTION AGREEMENT FOR INTERCONNECTION REQUESTS IN A QUEUE CLUSTER WINDOW
that are tendered a Large Generator Interconnection Agreement on or after July 3, 2010

* * *

ARTICLE 1. DEFINITIONS

* * *

NERC shall mean the North American Electric Reliability Corporation or its successor organization.

* * *

ARTICLE 5. INTERCONNECTION FACILITIES ENGINEERING, PROCUREMENT, AND CONSTRUCTION

5.16 Suspension. The Interconnection Customer reserves the right, upon written notice to the Participating TO and the CAISO, to suspend at any time all work associated with the construction and installation of the Participating TO's Interconnection Facilities, Network Upgrades, and/or Distribution Upgrades required under this LGIA, other than Network Upgrades identified in the Phase II Interconnection Study as common to multiple Generating Facilities, with the condition that the Participating TO's electrical system and the CAISO Controlled Grid shall be left in a safe and reliable condition in accordance with Good Utility Practice and the Participating TO's safety and reliability criteria and the CAISO's Applicable Reliability Standards. In such event, the Interconnection Customer shall be responsible for all reasonable and necessary costs which the Participating TO (i) has incurred pursuant to this LGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Participating TO's electric system during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which the Participating TO cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, the Participating TO shall obtain Interconnection Customer's authorization to do so.

The Participating TO shall invoice the Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work required under this LGIA pursuant to this Article 5.16, and has not requested the Participating TO to recommence the work or has not itself recommenced work required under this LGIA in time to ensure that the new projected Commercial Operation Date for the full Generating Facility Capacity of the Large Generating Facility is no more than three (3) years from the Commercial Operation Date identified in Appendix B hereto, this LGIA shall be deemed terminated and the Interconnection Customer's responsibility for costs will be determined in accordance with Article 2.4. The suspension period shall begin on the date the suspension is requested, or the date of the written notice to the Participating TO and the CAISO, if no effective date is specified.

* * *

Attachment C – Marked Tariff

Tariff Clarifications Filing

California Independent System Operator Corporation

Fifth Replacement FERC Electric Tariff

December 30, 2010

1.3.2 Specific Rules Of Interpretation Subject To Context

(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 CAISO Tariff;

(c) references to any law shall be deemed references to such law as it may be amended, replaced or restated from time to time;

(d) any reference to a "person" includes any individual, partnership, firm, company, corporation, joint venture, trust, association, organization or other entity, in each case, whether or not having separate legal personality;

(e) any reference to a day, month, week or year is to a calendar day, month, week or year;

(f) if the provisions of a CAISO Protocol and ~~Section 1 through 4~~a section of the CAISO Tariff conflict, the provisions ~~in Sections 1 through 4~~of the CAISO Tariff will prevail to the extent of the inconsistency;

(g) a reference to this CAISO Tariff or to a given agreement, or instrument shall be a reference to this CAISO Tariff or to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made;

(h) if the provisions of this CAISO Tariff and those of an existing contract conflict, with respect to Outage coordination, the existing contract will prevail to the extent of the inconsistency;

(i) time references are references to prevailing Pacific time;

(j) the Operating Procedures or Business Practice Manuals referenced in this CAISO Tariff, as may be amended from time to time, shall be posted on the CAISO Website, except as provided in Section 22.11, and such references in this

CAISO Tariff shall be to the Operating Procedures or Business Practice Manuals then posted on the CAISO Website;

(k) if the provisions of an Operating Procedure or a Business Practice Manual and this CAISO Tariff conflict, the CAISO Tariff will prevail to the extent of the inconsistency;

(l) any reference to a day or Trading Day, week, month or year is a reference to a calendar day, week, month or year except that a reference to a Business Day shall have the meaning set forth in Appendix A; and

(m) the captions and headings in this CAISO 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 CAISO Tariff.

* * *

4.3.1.2 With respect to its submission of Bids, including Self-Schedules, to the CAISO, a New Participating TO shall become a Scheduling Coordinator or obtain the services of a Scheduling Coordinator that has been certified in accordance with Section 4.5.1, 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 CAISO 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.

For the period between the effective date of this provision and ending December 31, 2010, the TAC Transition Date pursuant to Section 4.2 of Appendix F, Schedule 3, New Participating TOs that have joined the CAISO and turned over Operational Control of their facilities and Entitlements shall receive the IFM Congestion Credit in accordance with Section 11.2.1.5, which IFM Congestion Credit shall only be applicable to those facilities and Entitlements in existence on the effective date of the CAISO's initial assumption of Operational Control over the facilities and Entitlements of a New Participating TO.

4.5.1.3 Additional Scheduling Coordinator ~~Identification~~ID Code Registration

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

4.5.3.2.2 Submitting Interchange ~~schedules~~Schedules prepared in accordance with all NERC, WECC and CAISO requirements, including providing E-Tags for all applicable transactions pursuant to WECC practices;

4.5.3.7 ~~Annual and Monthly Forecasts~~[NOT USED]

~~Submitting to the CAISO its forecasted monthly and annual peak Demand in the CAISO Balancing Authority Area and/or its forecasted monthly and annual Generation capacity, as applicable; the forecasts shall be submitted to the CAISO electronically on a monthly basis by noon of the 18th working day of the month and shall cover a period of twelve (12) months on a rolling basis;~~

4.6 Relationship Between CAISO And Generators Version

The CAISO shall not accept Bids for any Generating Unit interconnected to the electric grid within the CAISO ~~Controlled Grid, or to the Distribution System of a Participating TO or of a UDC~~Balancing Authority Area otherwise than through a Scheduling Coordinator. The CAISO shall further not be obligated to accept Bids from Scheduling Coordinators relating to Generation from any Generating Unit interconnected to the ~~CAISO Controlled Grid~~electric grid within the CAISO Balancing Authority Area unless the relevant Generator undertakes in writing, by entering into a Participating Generator Agreement ~~or~~, QF PGA, or Metered Subsystem Agreement with the CAISO, to comply with all applicable provisions of this CAISO Tariff as they may be amended from time to time, including, without limitation, the applicable provisions of this Section 4.6 and Section 7.7.

4.6.3.1 Exemption for Generating Units Less Than One (1) MW

A Generator with a Generating Unit directly connected to a UDC system will be exempt from compliance with this Section 4.6 and Section 10.1.3 in relation to that Generating Unit provided that (i) the rated capacity of the Generating Unit is less than one (1) MW, and (ii) the Generator does not use the

Generating Unit to participate in the CAISO Markets. 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 CAISO Tariff. A Generating Unit with a rated capacity of less than 500 kW, unless the Generating Unit is participating in an aggregation agreement approved by the CAISO, is not eligible to participate in the CAISO Markets and the Generator is not a Participating Generator for that Generating Unit.

* * *

4.6.5 NERC and WECC Requirements Version

4.6.5.1 Participating Generator Performance Standard

Participating Generators shall, in relation to each of their Generating Units, meet all ~~a~~Applicable ~~WECC~~Reliability Criteria, ~~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 CAISO, a Generating Unit must be capable of operating at capacity registered in the CAISO Controlled Grid interconnection data, and shall follow the voltage schedules issued by the CAISO from time to time.

4.6.5.2 ~~Reliability Criteria~~[NOT USED]

~~Participating Generators shall comply with the requirements of the WSCC Reliability Criteria Agreement, including the applicable WSCC Reliability Criteria set forth in Section IV of Annex A thereof. In the event that a Participating Generator fails to comply, it will be subject to the sanctions applicable to such failure. Such sanctions shall be assessed pursuant to the procedures contained in the WSCC Reliability Criteria Agreement. Each and all of the provisions of the WSCC Reliability Criteria Agreement are hereby incorporated by reference into this Section 4.6.5.2 as though set forth fully herein, and Participating Generators shall for all purposes be considered Participants as defined in that Agreement, and shall be subject to all of the obligations of Participants, under and in connection with the WSCC Reliability Criteria Agreement. The Participating Generators shall copy the CAISO on all reports supplied to the WECC in accordance with Section IV of Annex A of the WSCC Reliability Criteria Agreement.~~

4.6.5.3 ~~Payment of Sanctions~~[NOT USED]

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

* * *

4.10.1.5.1 Information Requirements

The Candidate CRR Holder applicant must submit with its application:

(a) the proposed date for commencement of the CRR Allocation, CRR Auction or Secondary Registration System in which the applicant intends to qualify to participate, which may not be less than sixty (60) days after the date the application was filed, unless waived by the CAISO;

(b) financial Security information as set forth in Section 12;

(c) proof of completion of CRR training or expected completion of CRR training; ~~and~~

(d) the prescribed non-refundable application fee; and

(e) identity of the applicant's Affiliates, as described in Section 39.9.

* * *

4.10.2.2 Failure to Promptly Report a Material Change

If a Candidate CRR Holder or CRR Holder fails to inform the CAISO of a material change in its information provided to the CAISO including a Material Change in Financial Condition, that may affect the Financial Security of the CAISO, the CAISO may suspend or terminate the Candidate CRR Holder or CRR Holder's rights under the CAISO Tariff in accordance with the terms of Sections 12 and 4.10.~~4~~3.2, respectively. If the CAISO intends to terminate the Candidate CRR Holder's status, it shall file a notice of termination with FERC in accordance with the terms of the CRR Entity Agreement. Such termination shall be effective upon acceptance by FERC of a notice of termination in accordance with the terms of the CRR Entity Agreement.

* * *

6.5.1.1.1 Annually, the CAISO shall provide information that will include, but is not limited to, the following:

(a) CRR Full Network Model;

(b) Transmission Constraints and Transmission Interface definitions;

(c) Load Distribution Factors for each CRR Allocation and CRR Auction that is published prior to the CRR Allocation and CRR Auction; and

(d) Nominations and/or parameters to be used for modeling in each annual CRR Allocation and CRR Auction processes: Transmission Ownership Rights, Existing Contracts and Converted Rights expected usage, and Merchant Transmission CRRs.

6.5.1.1.2 Monthly, the CAISO shall provide information that will include, but is not limited to, the following:

(a) CRR Full Network Model;

(b) Transmission Constraints and Transmission Interface definitions;

(c) Load Distribution Factors for each CRR Allocation and CRR Auction that is published prior to the CRR Allocation or CRR Auction; and

(d) Nominations and/or parameters to be used for modeling in each monthly CRR Allocation and CRR Auction processes: Transmission Ownership Rights, Existing Contracts and Converted Rights expected usage, and Merchant Transmission CRRs.

* * *

6.5.2.1 Communications Regarding the State of the CAISO Controlled Grid

The CAISO shall use OASIS to provide public information to Market Participants regarding the CAISO Controlled Grid or facilities that affect the CAISO Controlled Grid. Such information may include but is not limited to:

(a) Future planned Outages of transmission facilities;

(b) ~~Operational~~Operating Transfer Capability (OTC); and

(c) Available Transfer Capability (ATC) for WECC paths and Transmission Interfaces with external Balancing Authority Areas.

* * *

6.5.2.2.2 Day-Ahead Market Bid Submittal

Seven (7) days prior to ~~the target~~any Trading Day~~-Ahead Market~~, Scheduling Coordinators can begin submitting Bids for the DAM for that ~~DAM~~Trading Day.

* * *

6.5.3.2.1 Before 10:00 a.m. one (1) day before the Operating Day~~)~~ the CAISO will publish updated Outage information regarding the transmission system on OASIS. The updated Outage information will include planned and actual Outage events per Transmission Interface, including Outage description, Outage start time and end time, and rating of the curtailed line.

6.5.3.2.2 The results of the Day-Ahead Market will be published on OASIS by 1:00 p.m. and will include:

(a) Total Day-Ahead Schedules (MWh) for total Supply and Demand by TAC Area and for the entire CAISO Balancing Authority Area;

(b) Total Day-Ahead Schedules (MWh) of imports and exports by Transmission Interface;

(c) Total Day-Ahead AS Awards by AS Region and AS type;

(d) RUC Prices by PNode and APNodes, RUC Forecast Demand for each RUC Zone, hourly RUC Capacity from Generation, and hourly RUC Capacity from imports for each TAC Area and the entire CAISO Balancing Authority Area;

(e) Day-Ahead LMP for Energy for each PNode and APNode, including the Energy, MCC and MCL components;

(f) Day-Ahead ASMP by AS Region and AS type;

(g) Day-Ahead mitigation indicator;

(h) CAISO Forecast of CAISO Demand for each TAC Area and the entire CAISO Balancing Authority Area;

(i) Shadow Prices of binding ~~transmission~~Transmission Constraints and an indication of whether the Transmission Constraints were binding because of the base operating conditions or a Contingency, and if caused by a Contingency, the identity of the specific Contingency; and

(j) Total Day-Ahead system Marginal Losses in MWh and Marginal Cost of Losses for each Trading Hour of the next Trading Day.

* * *

6.5.3.3 Communications with Market Participants

After the results of the Day-Ahead Market are posted, the CAISO will provide to parties that have signed a Non-Disclosure Agreement in accordance with Section 6.5.3.3.1, the daily post-Day-Ahead Market Transmission Constraints Enforcement List, which consists of the list of Transmission Constraints, including ~~contingencies~~Contingencies and ~~nomograms~~Nomograms that are enforced and not enforced in that day's Day-Ahead Market. Subsequently and prior to the next Day-Ahead Market, the CAISO will provide to parties ~~that~~ the pre-Day-Ahead Market Transmission Constraints Enforcement List, which consists of the daily list of information for the ~~transmission~~Transmission Constraints, including ~~contingencies~~Contingencies and ~~nomograms~~Nomograms, the CAISO plans to enforce or not enforce for the next day's Day-Ahead Market. To the extent that the CAISO does not make either of these two reports available on any given Operating Day, the CAISO will instead provide only the list of ~~transmission~~Transmission Constraints, including ~~contingencies~~Contingencies and ~~nomograms~~Nomograms, that were enforced or not enforced for the applicable Day-Ahead Market within the next thirty (30) days, after which the information will not be provided.

* * *

6.5.4.2.2 ~~At thirty (30~~No later than forty (40) minutes before the Trading Hour, on an hourly basis, the CAISO will publish on OASIS the following:

(a) Total HASP Intertie Schedules for imports and exports by TAC Area and for the entire CAISO Balancing Authority Area;

(b) HASP Intertie LMPs by PNodes and APNodes;

(c) HASP advisory LMPs by PNode and APNode;

(d) HASP Shadow Prices of binding Transmission Constraints and an indication of whether the constraints were binding because of the base operating conditions or contingencies and if caused by a contingency, the identity of the specific contingency; and

(e) Total HASP system Marginal Losses in MWh for the next Operating Hour.

* * *

6.5.6.1.1 The following information shall be published on OASIS ~~180~~ninety (90) days following the applicable Trading Day, with the exclusion of the information that is specific to Scheduling Coordinators:

(a) AS market Bids;

(b) Energy market Bids; and

(c) RUC market Bids.

* * *

6.5.7 Monthly Report on Conforming Transmission Constraints

The ~~ISO~~CAISO will post on its website a monthly report or incorporate into a monthly report on the degree of adjustments to ~~transmission~~Transmission Constraints made pursuant to Section 27.5.6. To the extent that in any given month the ~~ISO~~CAISO does not post on its website such reports, the ~~ISO~~CAISO will provide the report in the subsequent month. If it is not reasonably feasible to provide such the monthly report two months after the applicable month of the report, the information for the missed month will not be provided.

* * *

7.3.3 NAESB Standards

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

- Coordinate Interchange (WEQ-004, Version 001, October 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 004-0.1 through 004-17.2, and 004-A through 004-D;
- Area Control Error (ACE) Equation Special Cases Standards (WEQ-005, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 005-0.1 through 005-3.1.3, and 005-A;
- Manual Time Error Correction (WEQ-006, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 006-0.1 through 006-12;
- Inadvertent Interchange Payback (WEQ-007, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 007-0.1 through 007-2, and 007-A;
- Gas/Electric Coordination (WEQ-011, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Standards 011-0.1 through 011-1.6; ~~and~~
- Public Key Infrastructure (PKI) (WEQ-012, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Recommended Standard, Certification, Scope, Commitment to Open Standards, and Standards 012-0.1 through 012-1.26.5~~.~~; and
- Measurement and Verification of Wholesale Electricity Demand Response (WEQ-015, 2008 Annual Plan Item 5(a), March 16, 2009).

The CAISO has applied for a waiver of the following NAESB WEQ standards:

- Business Practices for Open Access Same-Time Information Systems (OASIS), Version 1.4 (WEQ-001, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Standards 001-0.2 through 001-0.8, 001-0.14 through 001-0.20, 001-2.0 through 001-9.6.2, 001-9.8 through 001-12.5.2, and 001-A and 001-B;

- Business Practices for Open Access Same-Time Information Systems (OASIS) Standards & Communication Protocols, Version 1.4 (WEQ-002, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Standards 002-0.1 through 002-5.10;
- Open Access Same-Time Information Systems (OASIS) Data Dictionary, Version 1.4 (WEQ-003, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Standard 003-0;
- Transmission Loading Relief – Eastern Interconnection (WEQ-008, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Purpose, Applicability, and Standards 008-0.1 through 008-3.11.2.8, and 008-A through 008-D; and
- Business Practices for Open Access Same-Time Information Systems (OASIS) Implementation Guide, Version 1.4 (WEQ-013, Version 001, Oct. 31, 2007, with minor corrections applied on Nov. 16, 2007) including Introduction and Standards 013-0.1 through 013-4.2.

* * *

7.7.8 Under Frequency Load Shedding (UFLS)

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

~~**7.7.8.2** The CAISO shall perform periodic audits of each UDC's UFLS system and of each MSS's UFLS system to verify that the system is properly configured for each UDC or MSS.~~

~~**7.7.8.3** The CAISO will use its reasonable endeavors to ensure that UFLS is coordinated among the UDCs and MSSs so that no UDC bears a disproportionate share of the CAISO's UFLS program.~~

~~**7.7.8.4** In compiling its UFLS program, the CAISO, at its discretion, may also coordinate with other entities, and review and audit their UFLS programs and systems as described in this Section 7.7.8.~~

* * *

7.7.15.4 Reporting Requirements under Section 7.7.15

The CAISO shall include reports on actions taken pursuant to Section 7.7.15 in the Exceptional Dispatch report provided in Section 34.9.4 of the ~~ISO~~CAISO Tariff. The report shall detail the frequency and types of actions taken by the CAISO pursuant to this Section 7.7.15, as well as the nature of the specific Market Disruptions that caused the CAISO to take action and the CAISO rationale for taking such actions, or the Market Disruption that was successfully prevented or minimized by the CAISO as a result of taking action pursuant to its authority under Section 7.7.15. This informational filing shall also contain general information on the Bids removed pursuant to Section 7.7.15, which may include the megawatt quantity, point of interconnection, specification of the Day-Ahead versus Real-Time Bid, and Energy or Ancillary Services Bid, and the CAISO's rationale for removal; provided, however, that any Scheduling Coordinator-specific individual Bid information will be submitted on a confidential basis consistent with FERC's rules and regulations governing requests for confidential treatment of commercially sensitive information.

* * *

8.3.1 Procurement Of Ancillary Services

The CAISO shall operate a competitive Day-Ahead Market, HASP, and Real-Time Markets to procure Ancillary Services. The Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) applications used in the Integrated Forward Market (IFM), HASP, and the Real-Time Market (RTM) shall calculate optimal resource commitment, Energy, and Ancillary Services Awards and Schedules at least cost to End-Use Customers consistent with maintaining System Reliability. Any Scheduling Coordinator representing Generating Units, System Units, Participating Loads, Proxy Demand Resources or imports of System Resources may submit Bids into the CAISO's Ancillary Services markets provided that it is in possession of a current certificate for the Generating Units, System Units, imports of System Resources, Participating Loads, or Proxy Demand Resources concerned. Regulation Up, Regulation Down, and Operating Reserves necessary to meet CAISO requirements not met by self-provision will be procured by the CAISO as described in this CAISO Tariff. The amount of Ancillary Services procured in the IFM is based on the CAISO Forecast of CAISO Demand

and the forecasted intertie schedules in HASP for the Operating Hour net of (i) Self-Provided Ancillary Services from Generating Units internal to the CAISO Balancing Authority Area and Dynamic System Resources certified to provide Ancillary Services and (ii) Ancillary Services self-provided pursuant to an ETC, TOR or Converted Right. The amount of additional Ancillary Services procured in the HASP is based on the CAISO Forecast of CAISO Demand, the Day-Ahead Schedules established net interchange, and the forecast of the intertie schedules for the Operating Hour in the HASP net of (i) available awarded Day-Ahead Ancillary Services, (ii) Self-Provided Ancillary Services from Generating Units internal to the CAISO Balancing Authority Area and Dynamic System Resources certified to provide Ancillary Services, and (iii) Ancillary Services self-provided pursuant to an ETC, TOR or Converted Right. The amount of Ancillary Services procured in the Real-Time Market is based upon the CAISO Forecast of CAISO Demand and the HASP Intertie Schedule established net interchange for the Operating Hour net of (i) available awarded Day-Ahead Ancillary Services, (ii) Self-Provided Ancillary Services from Generating Units internal to the CAISO Balancing Authority Area and Dynamic System Resources certified to provide Ancillary Services, (iii) additional Operating Reserves procured in HASP, and (iv) Ancillary Services self-provided pursuant to an ETC, TOR or Converted Right.

The CAISO will manage the Energy from both CAISO procured and Self-Provided Ancillary Services as part of the Real-Time Dispatch. In the Day-Ahead Market, the CAISO procures one-hundred percent (100%) of its Ancillary Service requirements based on the Day-Ahead Demand Forecast net of Self-Provided Ancillary Services. After the Day-Ahead Market, the CAISO procures additional Ancillary Services needed to meet system requirements from all resources, including imports from Non-Dynamic System Resources in the HASP, and Dynamic System Resources and Generation from internal resources in the Real-Time Market. The amount of Ancillary Services procured in the HASP and Real-Time Market is based ~~upon~~on the CAISO Forecast of CAISO Demand for the Operating Hour~~ and RTUC Time Horizon, respectively,~~ net of Self-Provided Ancillary Services.

The CAISO procurement of Ancillary Services from Non-Dynamic System Resources in the HASP is for the entire next Operating Hour. The CAISO procurement of Ancillary Services from Dynamic System Resources and internal Generation in the Real-Time Market is for a fifteen (15) minute ~~RTUC Time Horizon.~~time period to which the relevant RTUC applies. The CAISO's procurement of Ancillary Services from Non-Dynamic System Resources in HASP and from Dynamic System Resources and internal Generation in the Real-Time Market is based on the Ancillary Service Bids submitted or generated in the HASP consistent with the requirements in Section 30. The CAISO may also procure Ancillary Services pursuant to the requirements in Section 42.1 and as permitted under the terms and conditions of a Reliability Must-Run Contract.

~~As of the CAISO Operations Date, the~~The CAISO will contract for long-term Voltage Support service with owners of Reliability Must-Run Units under Reliability Must-Run Contracts.~~ ~~ The CAISO will procure Black Start capability~~ will initially be procured by the CAISO~~ through individual contracts with Scheduling Coordinators for Reliability Must-Run Units and other Generating Units which have Black Start capability. These requirements and standards apply to all Ancillary Services whether self-provided or procured by the CAISO.

* * *

8.3.3.2 Criteria For Use of Ancillary Service Regions and Sub-Regions

The CAISO's use of an Ancillary Service Sub-Region occurs when the CAISO establishes a minimum or maximum limit for that Sub-Region. The CAISO's use of minimum and maximum procurement limits for Ancillary Services help to ensure that the Ancillary Services required in the CAISO Balancing Authority Area are dispersed appropriately throughout the CAISO Balancing Authority Area and accurately reflect the system topology and deliverability needs. The factors the CAISO will ~~look to~~use in determining whether to establish or change minimum or maximum limits~~,~~ include, but are not limited to, the following: (a) the CAISO Forecast of CAISO Demand, (b) the location of Demand within the Balancing Authority Area, (c) information regarding network and resource operating constraints that affect the deliverability of Ancillary Services into or out of an Ancillary Service Region, (d) the locational mix of generating resources, (e) generating resource Outages, (f) historical patterns of transmission and generating resource availability, (g) regional transmission limitations and ~~Constraints~~constraints, (h) transmission Outages, (i) Available Transfer Capability, (j) DA Schedules or HASP Intertie Schedules, (k) whether any Ancillary Services provided from System Resources requiring a NERC tag fail to have a NERC tag, and (l) other factors affecting System Reliability. Ancillary Services procured within a Sub-Region count toward satisfying the Ancillary Service requirements for the System Region or the Expanded System Region.

8.3.3.3 Notice to Market Participants

Pursuant to Section 6.5.2.3.3, the CAISO will publish forecasted Ancillary Service requirements, regional constraints, and the minimum and/or maximum Ancillary Service Regional Limits for the Ancillary Service Regions and any Sub-Regions by 6:00 p.m. ~~prior to~~on the day before the close of the Day-Ahead Market (two days prior to the Operating Day). After the completion of the Day-Ahead Market for a given Trading Day, the CAISO will publish the limits that were used in the IFM. If prior to the close of the HASP for a Trading Hour the CAISO makes a substantial change to a minimum and/or maximum limit for an Ancillary Service Region or Sub-Region, it will issue a Market Notice as soon as reasonably practicable after the occurrence of the circumstances that led to the change. After the close of the HASP for a Trading Hour, the CAISO will publish the limits that were used in the HASP and RTUC.

* * *

8.3.3.5 Base Market Model and Ancillary Services Procurement

The Base Market Model is used in the SCUC application, which optimizes the provision of Ancillary Services and Energy in order to meet Ancillary Service requirements and Energy requirements. The Base Market Model models ~~network constraints~~Transmission Constraints as described in Section 27.5.1. The Ancillary Services Awards reflect the Ancillary Service Region and Sub-Region definitions and requirements. The Ancillary Service requirements, the definition of Ancillary Service Regions and Ancillary Service Sub-Regions, and any minimum or maximum limit that is used within an Ancillary Service Region or Ancillary Service Sub-Region are all inputs to the CAISO ~~Market~~Markets Processes.

* * *

8.9.3.1 Compliance Testing of a ~~Generating Unit, System Unit or System Resource~~Resources

The CAISO may test the Non-Spinning Reserve capability of a ~~Generating Unit, System Unit or an external import of a System Resource~~resource that is no Curtailable Demand by issuing unannounced Dispatch Instructions requiring the ~~Generating Unit or System Unit~~resource to come on line and ramp up or, in the case of a Proxy Demand Resource, to reduce Demand, or, in the case of a System Resource, to affirmatively respond to Real-Time ~~interchange schedule~~Interchange Schedule adjustment; all in accordance with the Scheduling Coordinator's Bid. Such tests may not necessarily occur on the hour. The CAISO shall measure the response of the ~~Generating Unit, System Unit or external import of a System Resource~~resource to determine compliance with its stated capabilities. For a Multi-Stage Generating Resource the full range of Non-Spinning capacity is evaluated at the applicable MSG Configuration.

* * *

8.9.15.2 Penalties for Failure to Pass Performance Audit

The Scheduling Coordinator for a provider of RUC Capacity or an Ancillary Service whose resource fails a performance audit shall be subject to the financial penalties provided for in the CAISO Tariff~~.~~, including those in Section 8.10. In addition, the sanctions described in Section 8.~~10~~9.16 shall ~~come into effect~~apply.

* * *

8.10.8.1 Rescission of Payments for Undispatchable Ancillary Service Capacity

The CAISO shall calculate the Real-Time ability of each Generating Unit, Participating Load, Proxy Demand Resource, System Unit or System Resource to deliver Energy from Ancillary Services capacity or Self-Provided Ancillary Services capacity for each Settlement Interval based on its maximum operating capability, actual telemetered output, and Operational Ramp Rate as described in Section 30.10. To make this determination for Multi-Stage Generating Resources the CAISO shall use the MSG-Configuration-specific Maximum Operating Limit and Operational Ramp Rate. System Resources that are awarded Ancillary Services ~~capacity in the Day-Ahead Market~~ are required to electronically tag (E-Tag as prescribed by the WECC) the Ancillary Services capacity. If the amounts of Ancillary Services capacity in an electronic tag differ from the amounts of Ancillary Services capacity for the System Resource, the Undispatchable Capacity will equal the amount of the difference, and will be settled in accordance with the provisions of Section 11.10.9.1.

* * *

9.3.6.5.1 ~~Calculation of Aggregate Generating Capacity~~[NOT USED]

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

~~(a) on an annual and quarterly basis, the CAISO 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 CAISO will calculate the aggregate daily peak Generation capacity projected to be available during the month.~~

* * *

9.3.10.6 With respect to Forced Outages of Generating Units that result in a reduction in maximum output capability that lasts fifteen (15) minutes or longer of 40 MW or more below the value registered in the Master File and ten (10) percent ~~(10%)~~ of the value registered in the Master File, the Operator shall provide to the CAISO an explanation of the Forced Outage and the estimated return time, within two (2) Business Days after the Operator initially notifies the CAISO pursuant to Section 9.3.10.~~2~~3.1 of the change in maximum output capability. The explanation shall include a description of the equipment failure or other cause and a description of all remedial actions taken by the Operator. Upon request of the CAISO, Operators, and where applicable, Eligible Customers, Scheduling Coordinators, UDCs and MSS Operators promptly shall provide information requested by the CAISO to enable the CAISO to review the changes made to the maximum output capability or to provide further information relative to the explanation of the Forced Outages submitted by the Operator and to prepare reports on Forced Outages. If the CAISO determines that any Forced Outage may have been the result of gaming or other questionable behavior by the Operator, the CAISO shall submit a report describing the basis for its determination to the FERC. The CAISO 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 Exceptional Dispatches; 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 CAISO 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 CAISO 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 CAISO an explanation of the Forced Outage within two (2) Business Days or failed to provide any additional information or access to the generating facility requested by the CAISO within a reasonable time.

* * *

9.5 ~~Records~~ Information About Outages

~~The CAISO and all Operators shall develop procedures to keep a record of Approved Maintenance Outages as they are implemented and to report the completion of Approved Maintenance Outages. Such records are available for inspection by Operators and Connected Entities at the CAISO 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 CAISO Outage Coordination Office, and such records will only be made available provided notice is given in writing to the CAISO fifteen (15) days in advance of the requested inspection date.~~

9.5.1 Approved Maintenance Outages

The CAISO and all Operators shall develop procedures to keep a record of Approved Maintenance Outages as they are implemented and to report the completion of Approved Maintenance Outages. Such records are available for inspection by Operators and Connected Entities at the CAISO 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 CAISO Outage Coordination Office, and such records will only be made available provided notice is given in writing to the CAISO fifteen (15) days in advance of the requested inspection date.

9.5.2 Publication to Website

The CAISO shall publish on the CAISO Website a list of all Generating Units that have been reported to the CAISO pursuant to the CAISO Tariff or contract as undergoing Outages, together with the Generating Unit's PMax, the amount of the curtailment, the name of its Scheduling Coordinator, and other non-confidential information about these Generating Units as CAISO determines.

* * *

10.2.8.2.1 Local Access

-If a CAISO Metered Entity desires to grant a third party local access to its revenue quality meters, those meters must be equipped with CAISO approved communications capabilities in accordance with the applicable Business Practice Manuals. The CAISO may set the password and any other security requirements for locally accessing the revenue quality meters of CAISO Metered Entities so as to ensure the security of those meters and their Revenue Quality Meter Data. The CAISO may alter the password and other requirements for locally accessing those meters from time to time as it determines necessary.

The CAISO must provide CAISO Metered Entities with the current password and other requirements for locally accessing their revenue quality meters. CAISO Metered Entities must not give a third party other than its Scheduling Coordinator local access to its revenue quality meters or disclose to that third party the password to its revenue quality meters without the CAISO's prior approval as set forth in a schedule to the Meter Service Agreement for CAISO Metered Entities which shall not unreasonably be withheld. CAISO Metered Entities will be responsible for ensuring that a third party approved by the CAISO to access its revenue quality meters only accesses the data it is approved to access and that the data are only accessed for the purposes for which the access was approved.

* * *

10.2.8.2.2 Remote Access

-The CAISO may set the password and any other security requirements for remotely accessing the revenue quality meters of CAISO Metered Entities so as to ensure the security of those meters and their Revenue Quality Meter Data. The CAISO will alter the password and other requirements for remotely accessing those meters from time to time as it determines necessary. The CAISO must provide CAISO

Metered Entities with the current password and other requirements for remotely accessing their revenue quality meters.

CAISO Metered Entities must not give a third party other than its Scheduling Coordinator remote access to its revenue quality meters or disclose to that third party the password to its revenue quality meters without the CAISO's prior approval as set forth in a schedule to the Meter Service Agreement for CAISO Metered Entities which shall not unreasonably be withheld. CAISO Metered Entities will be responsible for ensuring that a third party approved by the CAISO to access its revenue quality meters only accesses the data it is approved to access and that the data are only accessed for the purposes for which the access was approved.

* * *

10.3.6.2 Timing of Settlement Quality Meter Data Submission for Recalculation Settlement Statement T+38B

Scheduling Coordinators must submit Actual Settlement Quality Meter Data for the Scheduling Coordinator Metered Entities they represent to the CAISO no later than midnight on the forty-third (43) calendar day after the Trading Day (T+43C) for the Recalculation Settlement Statement T+38B. A Scheduling Coordinator that timely submits Actual Settlement Quality Meter Data for the Initial Settlement Statement T+7B pursuant to Section 10.3.6.1 may submit revised Actual Settlement Quality Meter Data for the Recalculation Settlement Statement T+38B no later than the forty-third (43) calendar day after the Trading Day pursuant to this Section.

(a) When Actual Settlement Quality Meter Data is not received by the CAISO for a Scheduling Coordinator Metered Entity by forty-three (43) calendar days after the Trading Day (T+43C), the Scheduling Coordinator has failed to submit complete and accurate meter data as required by Section 37.5.2.1 and will be subject to monetary penalty pursuant to Section 37.5.2.2.

(b) Any Scheduling Coordinator Estimated Settlement Quality Meter Data submitted by a Scheduling Coordinator on behalf of the Scheduling Coordinator Metered Entities it represents that is not replaced with Actual Settlement Quality Meter Data by forty-three

(43) calendar days after the Trading Day (T+43C) has failed to submit complete and accurate meter data as required by Section 37.5.2.1 and will be subject to monetary penalty pursuant to Section 37.5.2.2. In the absence of Actual Settlement Quality Meter Data, Scheduling Coordinator Estimated Settlement Quality Meter Data will be used in the Recalculation Settlement Statements.

~~-~~(c) The CAISO will not estimate a Scheduling Coordinator Metered Entity's Settlement Quality Meter Data for any outstanding metered Demand and/or Generation for use in a Recalculation Settlement Statement calculation. Any previous CAISO Estimated Settlement Quality Meter Data that the Scheduling Coordinator does not replace with Actual Settlement Quality Meter Data by forty-three (43) calendar days after the Trading Day (T+43C) will be set to zero. The CAISO will follow the control process described in the BPM for Metering to monitor and identify the CAISO Estimated Settlement Quality Meter Data that was not timely replaced and will take proactive measures to obtain the Actual Settlement Quality Meter Data. A Scheduling Coordinator that fails to replace CAISO Estimated Settlement Quality Meter Data with Actual Settlement Quality Meter Data by forty-three (43) calendar days after the Trading Day (T+~~43~~43C) has failed to provide complete and accurate Settlement Quality Meter Data as required by Section 37.5.2.1 and will be subject to monetary penalty pursuant to Section 37.5.2.2.

10.3.6.3 Timing of Settlement Quality Meter Data Submission for Recalculation Settlement Statements after the Recalculation Settlement Statement T+38B

Scheduling Coordinators may continue to submit Actual Settlement Quality Meter Data for the Scheduling Coordinator Metered Entities they represent to the CAISO for use in Recalculation Settlement Statements subsequent to the Recalculation Settlement Statement T+38B according to timelines established in the CAISO ~~Payment~~Payments Calendar.

* * *

11.1.5 Settlement Quality Meter Data For Initial Statement T+7B

The CAISO's Initial Settlement Statement T+7B shall be based on the Settlement Quality Meter Data (actual or Scheduling Coordinator estimated) received in SQMDS. In the event Actual Settlement Quality

Meter Data or Scheduling Coordinator Estimated Settlement Quality Meter Data is not received from a Scheduling Coordinator or CAISO Metered Entity, the CAISO will estimate Settlement Quality Meter Data for that outstanding metered Demand or Generation, excluding a Proxy Demand Resource, for the Initial Settlement Statement T+7B calculation.

(a) CAISO Estimated Settlement Quality Meter Data for metered Generation will be based on total Expected Energy and dispatch of that resource as calculated in the Real-Time Market and as modified by any applicable corrections to the Dispatch Operating Point for the resource.

(b) CAISO Estimated Settlement Quality Meter Data for metered Demand will be based on Scheduled Demand by the appropriate LAP. This value will be increased by fifteen (15) percent ~~(15%)~~ if the total actual system Demand in Real~~-~~-Time, as determined by the CAISO each hour, is greater than the total estimated metered demand by more than fifteen (15) percent~~ (15%).~~. Total estimated metered demand is the sum of the value of Scheduling Coordinator submitted metered Demand, CAISO polled estimated Settlement quality metered Demand, and Scheduled Demand for unsubmitted metered Demand at the fifth (~~5~~5th) Business Day after the Trading Day (T+5B). CAISO Estimated Settlement Quantity Meter Demand for Participating Load will not be increased by fifteen (15) percent~~ (15%).~~.

(c) CAISO will not estimate Settlement Quality Meter Data for Proxy Demand Resources.

* * *

11.2.4.5 CRR Balancing Account

The CRR Balancing Account shall accumulate: (1) the seasonal and monthly CRR Auction revenue amounts that were converted into daily CRRBA values as described in Section 11.2.4.3 and (2) any surplus revenue or shortfall generated from hourly CRR Settlements as described in Section 11.2.4.4. Interest accruing due to the CRR Balancing Account shall be at the CAISO's received interest rate and shall be credited to each monthly CRRBA Accrued Interest Fund, which is then allocated to monthly Measured Demand excluding Measured Demand associated with valid and balanced ETC, TOR, or ~~CVR~~

~~self-schedule~~Converted Rights Self-Schedule quantities for which IFM Congestion Credits and/or RTM Congestion Credits were provided in the same month.

11.2.5 Payment By OBAALSE For CRRs Through CRR Allocation Process

11.2.5.1 Pursuant to Section 36.9, in addition to other requirements specified therein, an OBAALSE will be eligible to participate in the CRR Allocation process if such entity has made a pre-payment to the CAISO and has met the requirements in Section 36.9. The prepayment amount shall equal the MW of CRR requested times the Wheeling Access Charge associated with the Scheduling Point corresponding to the CRR Sink times the number of hours in the period for each requested CRR MW amount. Except as provided in Section ~~39~~36.9.2, such prepayment will be made three (3) Business Days in advance of the submission of CRR nominations for Monthly CRRs, Seasonal CRRs and Long Term CRRs to the CRR Allocation. Within thirty (30) days following the completion of the CRR Allocation process for Monthly CRRs, Seasonal CRRs and Long Term CRRs, the CAISO shall reimburse such OBAALSE the amount of money pre-paid for any CRRs that were not allocated to the entity.

* * *

11.5.1 Instructed Imbalance Energy Settlements

For each Settlement Interval, IIE consists of the following types of Energy: (1) Optimal Energy; (2) HASP Scheduled Energy; (3) Residual Imbalance Energy; (4) Real-Time Minimum Load Energy; (5) Exceptional Dispatch Energy; (6) Regulation Energy; (7) Standard Ramping Energy; (8) Ramping Energy Deviation; (9) Derate Energy; (10) Real-Time Self-~~Schedule~~Scheduled Energy; (11) MSS Load Following Energy; (12) Real-Time Pumping Energy; and (13) Operational Adjustments for the Day-Ahead and Real-Time. Payments and charges for IIE attributable to each resource in each Settlement Interval shall be settled by debiting or crediting, as appropriate, the specific Scheduling Coordinator's IIE Settlement Amount. The IIE Settlement Amounts for the Standard Ramping Energy shall be zero. The IIE Settlement Amounts for Optimal Energy, Real-Time Minimum Load Energy, Regulation Energy, Ramping Energy Deviation, Derate Energy, Real-Time Pumping Energy, and Real-Time Self-Scheduled Energy shall be calculated as the product of the sum of all of these types of Energy and the Resource-Specific Settlement Interval LMP. For MSS Operators that have elected net Settlement, the IIE Settlement Amounts for Energy dispatched through the Real-Time Market optimization, Minimum Load Energy from System Units dispatched in Real-

Time, Regulation Energy, Ramping Energy Deviation, Derate Energy, MSS Load Following Energy, Real-Time Pumping Energy, and Real-Time Self-~~Schedule~~Scheduled Energy shall be calculated as the product of the sum of all of these types of Energy and the Real-Time Settlement Interval MSS Price. For MSS Operators that have elected gross Settlement, regardless of whether that entity has elected to follow its Load or to participate in RUC, the IIE for such entities is settled similarly to non-MSS entities as provided in this Section 11.5.1. The remaining IIE Settlement Amounts are determined as follows: (1) IIE Settlement Amounts for the Energy from the HASP Intertie Schedules is settled per Section 11.4; (2) IIE Settlement Amounts for Residual Imbalance Energy are determined pursuant to Section 11.5.5.; and (3) IIE Settlement Amounts for Exceptional Dispatches are settled pursuant to Section 11.5.6.

* * *

11.5.1.1 Total IIE Settlement Amount

The total IIE Settlement Amount ($) per Settlement Interval for each Scheduling Coordinator is the sum of the IIE Settlement Amounts for the Standard Ramping Energy, MSS Load Following Energy, Optimal Energy, Real-Time Minimum Load Energy, HASP Scheduled Energy, Regulation, Ramping Energy Deviation, Derate Energy, Real-Time Self-~~Schedule~~Scheduled Energy, Residual Imbalance Energy, Exceptional Dispatch Energy, Real-Time Pumping Energy and Operational Adjustments for the Day-Ahead and Real-Time.

11.5.1.2 Total IIE Quantity

The total IIE quantity (MWh) per Settlement Interval for each Scheduling Coordinator is the sum of Standard Ramping Energy, MSS Load Following Energy, Optimal Energy, HASP Scheduled Energy, Real-Time Minimum Load Energy, Regulation Energy, Ramping Energy Deviation, Derate Energy, Real-Time Self-~~Schedule~~Scheduled Energy, Residual Imbalance Energy, and Exceptional Dispatch Energy, Real-Time Pumping Energy, and Operational Adjustments for the Day-Ahead and Real-Time.

* * *

11.5.2 Uninstructed Imbalance Energy

Scheduling Coordinators shall be paid or charged a UIE Settlement Amount for each LAP, PNode or Scheduling Point for which the CAISO calculates a UIE quantity. UIE quantities are calculated for each resource that has a Day-Ahead Schedule, Dispatch Instruction, Real-Time Interchange Export Schedule or Metered Quantity. For MSS Operators electing gross Settlement, regardless of whether that entity has elected to follow its Load or to participate in RUC, the UIE for such entities is settled similarly to how UIE for non-MSS entities is settled as provided in this Section 11.5.2. The CAISO shall account for UIE in two categories: (1) Tier 1 UIE is accounted as the quantity deviation from the resource's IIE; and (2) Tier 2 UIE is accounted as the quantity deviation from the resource's Day-Ahead Schedule or as described in Section 11.2.5.4. For Generating Units, System Units of MSS Operators that have elected gross Settlement, Physical Scheduling Plants, System Resources and all Participating Load and Proxy Demand Resources, the Tier 1 UIE Settlement Amount is calculated for each Settlement Interval as the product of its Tier 1 UIE quantity and its Resource-Specific Tier 1 UIE Settlement Interval Price as calculated per Section 11.5.2.1, and the Tier 2 UIE Settlement Amount is calculated for each Settlement Interval as the product of its Tier 2 UIE quantity and the simple average of the relevant Dispatch Interval LMPs. The Tier 2 UIE Settlement Amount for non-Participating Load and MSS Demand under gross Settlement is settled as described in Section 11.5.2.2. ~~For resources within a System Unit of~~For MSS Operators that have elected net Settlement, the Tier 1 UIE Settlement Amount is calculated for each Settlement Interval as the product of its Tier 1 UIE quantity and its Real-Time Settlement Interval MSS Price, and the Tier 2 UIE Settlement Amount is calculated for each Settlement Interval as the product of its Tier 2 UIE quantity and the Real-Time Settlement Interval MSS Price. ~~The Tier 2 UIE Settlement Amount for non-Participating Load and MSS Demand under gross Settlement is settled as described in Section 11.5.2.2. For MSS Operators that have elected net Settlement, the Tier 2 UIE Settlement Amount for Demand of a net MSS Demand is calculated for the Trading Hour as the sum of the product of the hourly Tier 2 UIE quantity and the Real-Time Settlement Interval MSS Price.~~

* * *

11.5.6.2.5.1 Allocation of Exceptional Dispatch Excess Cost Payments to PTOs

The total Excess Cost Payments calculated pursuant to Section 11.5.6.2.3 for the IIE from Exceptional Dispatches instructed as a result of a transmission-related modeling limitation in the FNM as described in Section 34.9.3 in that Settlement Interval shall be charged to the Participating Transmission Owner in whose PTO Service Territory the transmission-related modeling limitation as described in Section 34.9.3

is located. If the modeling limitation affects more than one Participating TO, the Excess Cost Payments shall be allocated ~~pro-rata~~ in proportion to the ~~Participating TOs'~~ Transmission Revenue Requirements of the affected Participating TOs with PTO Service Territories. Costs allocated to Participating TOs under this section shall constitute Reliability Services Costs.

* * *

11.5.6.3.2 Allocation of Costs from Exceptional Dispatch Calls to Condition 2 RMR Units

(a) All costs associated with Energy provided by a Condition 2 RMR Unit operating other than according to a RMR Dispatch shall be allocated like other Instructed Imbalance Energy in accordance with Section 11.5.4.2.

(b) 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 under the RMR Contract have exceeded the applicable RMR Contract service limit,~~ shall be treated similar to costs under Section 11.5.6.2.5.2.

11.5.6.4 Settlement of IIE from Exceptional Dispatches ~~Used for Ancillary Services Testing, PMax Testing and Pre-Commercial Operation Testing for Generating Units~~for Testing

The Exceptional Dispatch Settlement price for incremental IIE that is consumed or delivered as a result of an Exceptional Dispatch for purposes of Ancillary Services testing, periodic testing, including PMax testing, or pre-commercial operation testing for Generating Units is the maximum of the Resource-Specific Settlement Interval LMP or the Default Energy Bid price. All Energy costs for these types of Exceptional Dispatch will be included in the IIE Settlement Amount described in Section 11.5.1.1.

* * *

11.8.6.5.3 Allocation of the RUC Compensation Costs

(i) In the first tier, the RUC Compensation Costs are allocated to Scheduling Coordinators, based on their Net Negative CAISO Demand Deviation in that

Trading Hour. The Scheduling Coordinator shall be charged at a rate which is the lower of (1) the RUC Compensation Costs divided by the Net Negative CAISO Demand Deviation for all Scheduling Coordinators in that Trading Hour; or (2) the RUC Compensation Costs divided by the RUC ~~Capacity~~Award, for all Scheduling Coordinators in that Trading Hour. Participating Load and Demand Response Providers shall not be subject to the first tier allocation of RUC Compensation Costs to the extent that the Participating Load's or Demand Response Provider's Net Negative CAISO Demand Deviation in that Trading Hour is incurred pursuant to a CAISO directive to consume in a Dispatch Instruction.

(ii) In the second tier, the Scheduling Coordinator shall be charged an amount equal to any remaining RUC Compensation Costs in proportion to the Scheduling Coordinator's metered CAISO Demand in any Trading Hour.

* * *

11.10.1.4 Voltage Support

The total payments for each Scheduling Coordinator for Voltage Support in any Settlement Period shall be the sum of the opportunity costs of limiting Energy output to enable reactive energy production in response to a CAISO instruction. The opportunity cost shall be calculated based on the product of the Energy amount that would have cleared the market at the price of the Resource-Specific Settlement Interval LMP minus the higher of the Energy Bid price or the Default Energy Bid price.

If applicable, Scheduling Coordinators shall also receive any payments under any long-term contracts due for the Settlement Period. Exceptional Dispatches for incremental or decremental Energy needed for Voltage Support procured through Exceptional Dispatch pursuant to Section 34.9.2 will be paid and settled in accordance with Sections 11.5.6.~~1 and 11.5.6.2.5.2.~~ RMR Units providing Voltage Support are compensated in accordance with the RMR Contract rather than this Section 11.10.1.4.

* * *

11.10.3.2 Hourly Net Obligation for Spinning Reserves

Each Scheduling Coordinator’s hourly net obligation for Spinning Reserves is determined as follows: the Scheduling Coordinator’s total Ancillary Services Obligation for Operating Reserve for the hour multiplied by the ratio of the CAISO’s total Ancillary Services Obligation for Spinning Reserves in the hour to the CAISO’s total Operating Reserve Obligations in the hour (and if negative, multiplied by NOROCAF), reduced by the accepted Self-Provided Ancillary Services for Spinning Reserves, plus or minus any Spinning Reserve Obligations for the hour acquired or sold through Inter-SC Trades of Ancillary Services.

The Scheduling Coordinator’s total Operating Reserve Obligation for the hour is the sum of five (5) percent ~~(5%)~~ of its Real-Time Demand (except the Demand covered by firm purchases from outside the CAISO Balancing Authority Area) met by Generation from hydroelectric resources plus seven (7) percent ~~(7%)~~ of its Demand (except the Demand covered by firm purchases from outside the CAISO Balancing Authority Area) met by Generation from non-hydroelectric resources, plus one hundred (100) percent ~~(100%)~~ of any Interruptible Imports, which can only be submitted as a Self-Schedule in the Day-Ahead Market, ~~and~~plus its scheduled on-demand obligations ~~which it schedules~~.

* * *

11.10.9.4 Allocation of Rescinded Ancillary Services Capacity Payments

Payments rescinded pursuant to Sections 8.10.8 and 11.10.9 shall be allocated to Scheduling Coordinators in proportion to ~~CAISO Balancing Authority Area Measured Demand for the same Trading Day. Regulation capacity payments rescinded pursuant to Section 8.10.8.6 shall be allocated to Scheduling Coordinators in proportion to CAISO Balancing Authority Area metered CAISO Demand~~their Ancillary Services Obligation for the same Trading Day.

* * *

11.13.10 Confidentiality

The provisions of Sections 11.29.10.~~1~~5 and 20.5 shall apply to this Section 11.13 between and among the RMR Owners, the CAISO and Responsible Utilities. Except as may otherwise be required by applicable law, all confidential information and data provided by RMR Owner or the CAISO to the Responsible Utility pursuant to the RMR Contract, Section 41.6 or this Section 11.13 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.

* * *

11.19.1.2 Annual Charges Assessment

Scheduling Coordinators shall pay FERC Annual Charges assessed against them by the CAISO on a monthly or annual basis. Scheduling Coordinators that pay FERC Annual Charges on a monthly basis shall make the payment for such charges within five (5) Business Days after issuance of the market Invoice or Payment Advice containing the charges. Scheduling Coordinators that must pay FERC Annual Charges on an annual basis shall make the payment for such charges within five (5) Business Days from the Payment Date stated on the Invoice for FERC Annual Charges. ~~The~~ For Scheduling Coordinators electing monthly settlement of the FERC Annual Charges, these charges are assessed for a given Trading Month ~~that are due monthly will be issued to Scheduling Coordinators twice a month in accordance with the CAISO Payments Calendar~~ in the same semi-monthly Invoice and Payment Advice ~~that contains~~containing the market Settlement and Grid Management Charge~~. The FERC Annual Charges for a given trading month that are due annually will be issued to~~ issued in accordance with the CAISO Payment Calendar. For Scheduling Coordinators ~~twice a month~~electing yearly assessment of the FERC Annual Charges, the charges for a given Trading Month that are due annually are issued in accordance with the CAISO Payment Calendar on the same day as the market Invoice ~~and~~or Payment Advice but in a separate Invoice as indicated in Section 11.29.10. Further the FERC Annual Charges amounts are provided to Scheduling Coordinators at least twice a month in their Settlement Statements. Once the final FERC Annual Charge Recovery Rate is received from FERC in the spring or summer of the following year, revised FERC Annual Charges will be calculated and included on a supplemental Invoice or Payment Advice. All Scheduling Coordinators shall make payment for such charges within five (5) Business Days after the CAISO issues such supplemental Invoice.

* * *

11.19.3.4 Under- or Over-Recovery of FERC Annual Charge Recovery Rate

~~-~~If the FERC Annual Charges assessed by FERC against the CAISO for transactions on the CAISO Controlled Grid during any year exceed or fall short of funds collected by the CAISO for FERC Annual Charges with respect to that year by a range of ten (10) percent ~~(10%)~~ or less, the CAISO shall take such under- or over-recovery into account through an adjustment to the FERC Annual Charge Recovery Rate in accordance with this Section. Any deficiency of available funds necessary to pay for any assessment of FERC Annual Charges payable by the CAISO may be covered by an advance of funds from the CAISO's Grid Management Charge, provided any such advanced funds will be repaid. If the CAISO's collection of funds for FERC Annual Charges with respect to any year results in an under- or over-recovery of greater than ten (10) percent ~~(10%),~~, the CAISO 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~~The surcharge or credit shall be allocated among all active Scheduling Coordinators based on the percentage of ~~each~~the surcharge or credit that reflects the 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 CAISO in accordance with this CAISO Tariff at the time the CAISO issues a surcharge or credit under this section. The CAISO will issue any surcharges or credits under this section within sixty (60) days of receiving a FERC Annual Charge assessment from the FERC.

* * *

11.19.4 Credits And Debits Of FERC Annual Charges From SCs

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

* * *

11.20.5 Timely Payments

~~-~~Scheduling Coordinators shall make timely payments to the ~~ISO~~CAISO pursuant to Preliminary NERC/WECC Charge Invoices within thirty (30) calendar days of issuance of such invoices. Scheduling

Coordinators shall make timely payments to the CAISO pursuant to Final NERC/WECC Charge Invoices within fifteen (15) Business Days of issuance of such invoices.

* * *

11.20.7.3 Disputes and ~~Disput~~Dispute-Related Corrections

Scheduling Coordinators shall be prohibited from disputing any Preliminary NERC/WECC Charge Invoice or Final NERC/WECC Charge Invoice, except on grounds that an error in a Preliminary NERC/WECC Charge Invoice or Final NERC/WECC Charge Invoice is due to a mere typographical or other ministerial error by the CAISO. A Scheduling Coordinator that wishes to dispute a NERC/WECC Charge Invoice on such grounds shall give the CAISO notice of dispute in writing within ten (10) calendar days of issuance. The notice of dispute shall state clearly the issue date of the Preliminary NERC/WECC Charge Invoice or Final NERC/WECC Charge Invoice, the item or calculation disputed, and the reasons for the dispute, and shall be accompanied by all available evidence reasonably required to support the claim. If the Scheduling Coordinator is correct that the Preliminary NERC/WECC Charge Invoice or Final NERC/WECC Charge Invoice contains a typographical or other ministerial error and the resolution of the dispute makes correction necessary, the CAISO shall issue a corrected Preliminary NERC/WECC Charge Invoice or a corrected Final NERC/WECC Charge Invoice within fifteen (15) calendar days of issuance of the invoice that is being corrected.

Each Scheduling Coordinator that receives a Preliminary NERC/WECC Charge Invoice or a Final NERC/WECC Charge Invoice shall pay any net debit and shall be entitled to receive any net credit in a Preliminary NERC/WECC Charge Invoice or a Final NERC/WECC Charge Invoice on the Payment Date, regardless of whether there is any dispute regarding the amount of the debit or credit. The CAISO will issue corrected Preliminary NERC/WECC Charge Invoices or corrected Final NERC/WECC Charge Invoices if the resolution of a dispute concerning a Preliminary NERC/WECC Charge Invoice or a Final NERC/WECC Charge Invoice, brought pursuant to this Section 11.20, makes such a correction necessary.

* * *

11.21.1 CAISO Demand and Exports

If the CAISO corrects an LMP in the upward direction pursuant to Section 35 that impacts Demand in the Day-Ahead Market and the HASP such that either a portion of or the entire cleared CAISO Demand or export Economic Bid curve becomes uneconomic, then the CAISO will calculate and apply the Price Correction Derived LMP for settlement of CAISO Demand and exports in Section 11.2.1.2, 11.2.3, 11.2.1.4 and 11.4.1. The CAISO will calculate a Price Correction Derived LMP for each affected CAISO Demand and exports as follows: the total cleared MWhs of CAISO Demand or exports in the Day-Ahead Schedule or HASP Intertie Schedule, as applicable, multiplied by the corrected LMP, minus the make-whole payment amount, all of which is divided by the total cleared MWhs of CAISO Demand or export in the Day-Ahead Schedule or HASP Intertie Schedule, as applicable. The make-whole payment amount will be calculated on an hourly basis determined by the area between the Scheduling Coordinator's CAISO Demand or Export Bid curve and the corrected LMP, which is calculated as the MWhs for each of the cleared bid ~~segment~~segments in the Day-Ahead Schedule or HASP Intertie Schedule for the affected resource, multiplied by the maximum of zero or the corrected LMP minus the bid segment price. For the purpose of this calculation, the CAISO will not factor in a make-whole payment amount for Self-Scheduled CAISO Demand or exports. Any non-zero amounts in revenue collected as a result of the application of the Price Correction Derived LMP will be captured through the calculation of the Congestion Charge reflected in Section 11.2.4.1 and the allocation of non-zero amounts of the sum of Imbalance Energy, Uninstructed Imbalance Energy, and Unaccounted for Energy in accordance with Section 11.5.4.

* * *

11.22.2.5.8 Settlements, Metering, and Client Relations Charge

The Settlements, Metering, and Client Relations Charge for each Scheduling Coordinator is fixed at $1000.00 per month, per Scheduling Coordinator ID Code with ~~an~~a non-zero invoice value ~~other than $0.00~~where the non-zero value reflects market activity in the current Trading Month, as indicated in Appendix F, Schedule 1, Part A, subject to the requirements set out in Appendix F, Schedule 1, Part F. 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 in Appendix F, Schedule 1, Part E.

* * *

11.29.5.2 Right to Dispute

All Scheduling Coordinators, CRR Holders, Black Start Generators or Participating TOs shall have the right to dispute any item or calculation set forth in any Initial Settlement Statement T+7B, Recalculation Settlement Statement T+38B, or Incremental Changes in Recalculation Settlement Statements T+76B, T+18M, and T+35M in accordance with this CAISO Tariff, but not those set forth in Recalculation Settlement Statement T+36M.

* * *

11.29.7.1 Timing of the Settlements Process

The CAISO will publish: (i) Initial Settlement Statements T+7B on the seventh Business Day from the relevant Trading Day (T+7B), (ii) Recalculation Settlement Statements on the thirty-eighth Business Day from the relevant Trading Day (T+38B), (iii) Recalculation Settlement Statements on the seventy-sixth Business Day after the Trading Day (T+76B), (iv) Recalculation Settlement Statements on the Business Day eighteen (18) calendar months from the relevant Trading Day (T+18M) if necessary, (v) Recalculation Settlement Statements on the Business Day thirty-five (35) calendar months from the relevant Trading Day (T+35M) if necessary, (vi) Recalculation Settlement Statements on the Business Day thirty-six (36) calendar months from the relevant Trading Day (T+36M) if necessary, and (v) any other Recalculation Settlement Statement authorized under Section 11.29.7.3. The CAISO will issue a notice to the market if a Recalculation Settlement Statement T+18M, Recalculation Settlement Statement T+35M, Recalculation Settlement Statement T+36M, or any additional Recalculation Settlement Statement is required for a Trading Day. The CAISO will notify affected Market Participants regarding failed or late publication of any settlement statements specified above and will rectify such failed or late publications pursuant to its procedure posted on the CAISO Website.

11.29.7.1.1 Initial Settlement Statement T+7B

The CAISO shall provide to each Scheduling Coordinator, CRR Holder, Black Start Generator or Participating TO for validation an Initial Settlement Statement T+7B for each Trading Day within seven (7) Business Days of the relevant Trading Day, covering all Settlement Periods in that Trading Day. Each Initial Settlement Statement T+7B will be produced using available Settlement Quality Meter Data (either actual or estimated) and CAISO Estimated Settlement Quality Meter Data. The Initial Settlement Statement T+~~TB~~7B will include the following:

(a) the amount payable or receivable by the Scheduling Coordinator, CRR Holder, Black Start Generator or Participating TO for each charge referred to in Section 11 for each Settlement Period in the relevant Trading Day;

(b) the total amount payable or receivable by that Scheduling Coordinator, CRR Holder, Black Start Generator or Participating TO for each charge for all Settlement Periods in that Trading Day after the amounts payable and the amounts receivable under (a) have been netted off pursuant to Section 11.29; and

(c) the components of each charge in each Settlement Period except for information contained in the Imbalance Energy report referred to in this Section 11.29.7.1.1; and

(d) a breakdown of the components of the Imbalance Energy charge (the Imbalance Energy report).

11.29.7.1.2 Recalculation Settlement Statements

The CAISO shall provide to each Scheduling Coordinator, CRR Holder, Black Start Generator or Participating TO Recalculation Settlement Statements in accordance with the CAISO Tariff and the CAISO Payments Calendar. Recalculation Settlement Statements shall be in a format similar to that of the Initial Settlement Statement T+7B and shall include the same granularity of information provided in the Initial Settlement Statement T+~~TB~~7B as amended following the validation procedure.

* * *

11.29.7.3 Additional Recalculation Settlement Statements

* * *

11.29.7.3.4 ~~Re-runs~~Recalculation Settlement Statements, post closing adjustments and the financial outcomes of CAISO ADR Procedures and any other dispute resolution may be invoiced ~~separately~~separtely from monthly market activities~~. The CAISO shall provide a Market Notice at least~~

~~thirty (30) days prior to such invoicing identifying the components of such Invoice or Payment Advice~~ in accordance with Section 11.29.10.3.

* * *

11.29.9.6.1 Clearing Account

(a) Subject to Section 11.29.3, and unless the CAISO instructs otherwise pursuant to Section 11.29.11, each CAISO Debtor shall remit to the CAISO Clearing Account the amount shown on the Invoice as payable by that CAISO Debtor for value not later than 10:00 a.m. on the Payment Date.

(b) On the Payment Date the CAISO shall be entitled to cause the transfer of such amounts held in a Scheduling Coordinator's or CRR Holder's CAISO prepayment account to the CAISO Clearing Account as provided in Section 11.29.3.

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

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

* * *

11.29.10.6 Payment of Estimated Statements and Invoices

When estimated Settlement Statements and Invoices or Payment Advices are issued by the CAISO, payments between the CAISO and Market Participants shall be made on an estimated basis and the necessary corrections shall be made by the CAISO as soon as practicable. The corrections will be reflected as soon as practicable in later Settlement Statements and Invoices and Payment Advices issued by the CAISO unless the CAISO has authorized the adjustment pursuant to Section 11.29.11. Failure to make such estimated payments shall result in the same consequences as a failure to make actual payments.

* * *

11.29.11 Instructions For Payment

~~Each~~Unless the CAISO instructs otherwise, each Scheduling Coordinator or CRR Holder shall remit to the CAISO Clearing Account the amount shown on the Invoice as payable by that Scheduling Coordinator or CRR Holder for value not later than 10:00 a.m. ~~on the Payment Date.~~ on the Payment Date. In the event of a verifiable error that would be reversed on a future Invoice, the CAISO may instruct a Scheduling Coordinator or CRR Holder not to remit payment for a specific charge shown on an Invoice. Any such occurrence will not constitute a payment default under the CAISO Tariff. If the payment amount would otherwise be payable to identified Market Participants, the CAISO will inform those entities that they will not be receiving payment for any specific corresponding charge code on a Payment Advice

* * *

11.31.1 Decline Monthly Charge – Imports

The Decline Monthly Charge – Imports shall be applied to each Scheduling Coordinator on the Settlement Statements issued for the last Trading Day of each Trading Month, and shall be the sum of the Scheduling Coordinator's Decline Potential Charges – Imports for each Settlement ~~Interval~~Period during that Trading Month multiplied by a ratio. The ratio will represent the portion of the Scheduling Coordinator's declined HASP Intertie Schedules for Energy imports that exceed the applicable exemption threshold during the Trading Month.

(a) The ratio will be calculated as follows:

(i) the Scheduling Coordinator's total MWh quantity of HASP Intertie Schedules for Energy imports that were not delivered during that Trading Month minus the applicable exemption threshold, divided by

(ii) the Scheduling Coordinator's total MWh quantity of HASP Intertie Schedules for Energy imports that were not delivered during the Trading Month.

(b) The applicable exemption threshold is the greater of the following:

(i) the Decline Threshold Quantity – Imports/Exports; or

(ii) the total MWh quantity of HASP Intertie Schedules for Energy imports during the Trading Month multiplied by the Scheduling Coordinator's Decline Threshold Percentage – Imports/Exports.

Notwithstanding the foregoing, the Decline Monthly Charge – Imports shall equal zero if either:

a) The percentage of the MWh quantity of HASP Intertie Schedules for Energy imports that the Scheduling Coordinator did not deliver during the Trading Month is less than the Decline Threshold Percentage – Imports/Exports; or

b) The total MWh quantity of HASP Intertie Schedules for Energy imports that the Scheduling Coordinator did not deliver in the applicable Trading Month is less than the Decline Threshold Quantity – Imports/Exports.

* * *

12.1.3.1.1 Calculation of the Estimated Aggregate Liability Amount

Except as described in Section 12.1.3.1.2, the CAISO shall use the method described in this Section 12.1.3.1.1 to calculate each Market Participant's Estimated Aggregate Liability. The Estimated Aggregate Liability represents the amount owed to the CAISO for all unpaid obligations, specifically, the obligations for the number of Trading Days outstanding at a given time based on the CAISO's Payments Calendar plus five (~~7~~5) Trading Days based on the allowable period for Market Participants to respond to CAISO requests for additional Financial Security collateral (three (3) Business Days), and other liabilities including the value of a Market Participant's CRR portfolio, if negative. The charges the CAISO shall use to calculate Estimated Aggregate Liability shall be charges described or referenced in the CAISO Tariff. The CAISO shall calculate the Estimated Aggregate Liability for each Market Participant by aggregating the following obligations:

- invoiced amounts, i.e., any published but unpaid amounts on Invoices;
- published amounts, i.e., amounts for Trading Days for which Settlement Statements have been issued;
- estimated amounts, i.e., amounts based on estimated Settlement amounts calculated by the Settlement system using estimated meter data, and other available operational data;
- extrapolated amounts, i.e., amounts calculated for Trading Days for which neither actual nor estimated Settlement Statements have been issued;
- CRR portfolio value, i.e., the prospective value of the CRR portfolio, if negative, as described in Section 12.6.3;
- CRR Auction limit, i.e., the maximum credit limit for participation in a CRR Auction;
- CRR Auction awards (prior to invoicing), i.e., amounts to cover winning offers at the completion of the CRR Auction bur prior to invoicing;
- past-due amounts, i.e., any unpaid or past due amounts on Invoices;
- FERC Annual FERC Charges, i.e., FERC Annual Charges for a Market Participant that has elected to pay such amounts on an annual basis that are owed and outstanding and not already captured in any other component of Estimated Aggregate Liability;
- WAC Charges, i.e., WAC amounts for the current year or future years as specified in Section 36.9.2;
- Estimated Aggregate Liability adjustments, i.e., adjustments that may be necessary as a result of analysis performed as a result of Section 12.4.2; and

- extraordinary adjustments, i.e., adjustments to Settlement amounts related to FERC proceedings, if known and estimated by the CAISO, as described in Section 12.1.3.1.3.

For a Market Participant that maintains multiple BAID numbers, the Estimated Aggregate Liability of the Market Participant as a legal entity shall be calculated by summing the Estimated Aggregate Liabilities for all such BAID numbers and comparing the sum of the Estimated Aggregate Liabilities to the Aggregate Credit Limit of the Market Participant. Market Participants may recommend changes to the liability estimates produced by the CAISO's Estimated Aggregate Liability calculation through the dispute procedures described in Section 12.4.2.

* * *

12.5.1 Enforcement Actions Re Under-Secured Market Participants

If a Market Participant's Estimated Aggregate Liability, as calculated by the CAISO, at any time exceeds its Aggregate Credit Limit, the CAISO may take any or all of the following actions:

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

(b) The CAISO may limit trading, which may include rejection of Bids, including Self-Schedules, rejection or cancellation of Inter-SC Trades in their entirety (i.e., both sides of the Inter-~~SCE~~SC Trade) at any time, and/or limiting other CAISO Market activity, including limiting eligibility to participate in a CRR Allocation or CRR Auction. In such case, the CAISO shall notify the Market Participant of its action and the Market Participant shall not be entitled to participate in the CAISO Markets or CRR Auctions or submit further Bids, including Self-Schedules, or otherwise participate in the CAISO Markets until the Market Participant posts an additional Financial Security Amount that is sufficient to ensure that the Market Participant's Aggregate Credit Limit is at least equal to its Estimated Aggregate Liability.

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

(d) The CAISO may restrict, suspend, or terminate the Market Participant's CRR Entity Agreement or any other service agreement.

(e) The CAISO may resell the CRR Holder's CRRs in whole or in part, including any Long Term CRRs, in a subsequent CRR Auction or bilateral transaction, as appropriate.

(f) The CAISO will not implement the transfer of a CRR if the transferee or transferor has an Estimated Aggregate Liability in excess of its Aggregate Credit Limit.

In addition, the CAISO may restrict or suspend a Market Participant's right to submit further Bids, including Self-Schedules, or require the Market Participant to increase its Financial Security Amount if at any time such Market Participant's potential additional liability for Imbalance Energy and other CAISO charges is determined by the CAISO to be excessive by comparison with the likely cost of the amount of Energy reflected in Bids or Self-Schedules submitted by the Market Participant.

* * *

13.5.2 Timing Of Adjustments

Upon determination that an award is payable by or to the CAISO pursuant to good faith negotiations or the CAISO ADR Procedures, the CAISO 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 Initial Settlement Statement T+~~38BD~~7B or, in the case of an amount payable by the CAISO to a party, as soon as the CAISO and that party may agree.

* * *

14.5.2 Exclusion Of Certain Types Of Loss

The CAISO 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 gross negligence or intentional wrongdoing on the part of the CAISO.

19. **[NOT USED]**

19.1 **[NOT USED]**

19.1.1 **[NOT USED]**

~~This Section 19.1 shall apply to each Scheduling Coordinator that must submit a Demand Forecast pursuant to Section 4.5.3.7 or the provisions of Section 40, and each Load Serving Entity on whose behalf such Demand Forecasts are submitted.~~

19.1.2 **[NOT USED]**

~~Each Scheduling Coordinator submitting a Demand Forecast to the CAISO, and each Load Serving Entity on whose behalf such Demand Forecast is submitted, shall ensure, to the best of their ability, that any Demand Forecast submitted to the CAISO is not duplicated in another Scheduling Coordinator's Demand Forecast.~~

19.1.3 **[NOT USED]**

~~Each Scheduling Coordinators submitting a Demand Forecast to the CAISO, and each Load Serving Entity on whose behalf such Demand Forecast is submitted, shall take all necessary actions to provide a Demand Forecasts that reflects reasonable forecast accuracy standards.~~

* * *

20.4 Disclosure

Notwithstanding anything in this Section 20 to the contrary,

* * *

(e) Notwithstanding the provisions of Section 20.2(f), information submitted through the Transmission Planning Process shall be disclosed as follows:

(i) Critical Energy Infrastructure Information may be provided to a requestor where such person is employed or designated to receive CEII by: (a) a Market Participant; (b) an electric utility regulatory agency within California; (c) an Interconnection Customer that has submitted an Interconnection Request to the CAISO under the CAISO's Large Generator Interconnection Procedure or Small Generator Interconnection Procedure (LGIP or SGIP); (d) a developer having a pending or potential proposal for development of a Generating Facility or transmission addition, upgrade or facility and that is performing studies in contemplation of filing an Interconnection Request or submitting a transmission infrastructure project through the ~~ISO~~CAISO Transmission Planning Process; or (e) a not-for-profit organization representing consumer regulatory or environmental interests before a Local Regulatory Authority or federal regulatory agency. To obtain Critical Energy Infrastructure Information, the requestor must submit a statement as to the need for the CEII, and must execute and return to the CAISO the form of the non-disclosure agreement and non-disclosure statement included as part of the Business Practice Manual. The CAISO may, at its sole discretion, reject a request for CEII and upon such rejection, the requestor will be directed to utilize the FERC procedures for access to the requested CEII.

(ii) Information that is confidential under Section 20.2(f)(i) or 20.2.(f)(ii) may be disclosed to any individual designated by a Market Participant, electric utility regulatory agency within California, or other stakeholder that signs and returns to the CAISO the form of the non-disclosure agreement, nondisclosure statement and certification that the individual is a non-Market Participant, which is any person or entity not involved in a marketing, sales, or brokering function as market, sales, or brokering are defined in FERC's Standards of Conduct for Transmission Providers (18 C.F.R. § 358 et seq.), included as part of the Business Practice Manual; provided, however, that information obtained pursuant to this Section 20.~~2(f~~4(e)(ii) will be provided only in composite form so that information related to individual Load Serving Entities or Scheduling Coordinators will not be disclosed~~; and~~.

~~-~~(iii) Data base and other transmission planning information obtained from the WECC, or its successor, may be disclosed to individuals designated by a Market Participant, electric utility regulatory agency within California, or other stakeholder in accordance with the procedures set forth in the Business Practice Manual.

Nothing in this Section 20 shall limit the ability of the CAISO to aggregate data for public release about the adequacy of supply.

* * *

22.4.1 Effectiveness

Any notice, demand, or request in accordance with this CAISO Tariff, unless otherwise provided in this CAISO Tariff, 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~~(d) upon receipt of confirmation by return e-mail if sent by e-mail, or (e) upon delivery if delivered by prepaid commercial courier service.

* * *

22.4.3 Notice Of Changes In Operating Procedures And BPMs

The CAISO will issue notice of any changes to any Operating Procedure or proposed changes to any ~~Operating Procedure or~~ Business Practice Manual. The effective date of any change or proposed change in any ~~Operating Procedure or~~ Business Practice Manual shall be established as part of the change management process set forth in Section 22.11 but will be no earlier than at least thirty (30) days from the date of publication of a Market Notice describing the change or proposed change, unless: (1) a different notice period is specified by state or federal law, (2) the change falls within Category A of Section 22.11.1.4(a) in which case the provisions of that section shall apply; (3) the change is reasonably required to address an emergency affecting the CAISO Controlled Grid or its operations, or (~~3~~4) the change is to a provision of a Business Practice Manual that is necessitated by emergency circumstances specific to that Business Practice Manual. Such circumstances include, but are not limited to, any change necessary to ensure that the Business Practice Manual is consistent with the CAISO Tariff or any applicable law, regulation, NERC or WECC operating policies, guidelines and standards, or FERC order, in which case the CAISO shall give Market Participants as much notice as is reasonably practicable. Any notices issued under this provision shall be issued in accordance with the procedures set out in Section 22.11.

* * *

22.11.1.5 BPM PRR Review and Action

Any interested stakeholder or CAISO management may comment on a posted BPM PRR in accordance with the process set forth in the Business Practice Manual for BPM change management. To receive consideration, comments must be delivered electronically to the CAISO within ten (10) Business Days, or within any shorter period determined to be necessary or appropriate pursuant to the provisions of either Sections 22.11.1.7 or 22.11.1.8. Comments shall be posted to the CAISO Website~~. After their comment periods have expired,~~ and BPM PRRs shall be considered by the CAISO at a regularly established monthly public meeting or specially-noticed meeting dedicated to that purpose. Following any meeting to consider pending BPM PRRs and subject to the standards set forth in Section 22.11.1.4, the BPM change management coordinator shall issue a recommendation for action on each pending BPM PRR and shall publish for public comment a report on the recommendation in accordance with the procedures set forth in the Business Practice Manual for BPM change management. The report shall be sufficiently detailed and shall be published in a timeframe that allows interested stakeholders a meaningful opportunity to provide written comment. The BPM change management coordinator shall publish a final decision on any BPM PRR after considering stakeholder comments and all relevant impacts on their business needs and after the PRR recommendation report and comments concerning it have been discussed at a BPM change management meeting, in accordance with procedures set forth in the Business Practice Manual for BPM change management.

22.11.1.6 Right to Appeal to CAISO

Any entity eligible to submit a BPM PRR under Section 22.11.1.1 may, within ten (10) Business Days, appeal in writing the outcome of any BPM PRR to a committee comprising at least three CAISO executives established in accordance with procedures set forth in the Business Practice Manual for BPM change management. The CAISO will establish a standing meeting time for the BPM appeals committee to be used if needed and will establish the composition of the BPM appeals committee, including alternates in the case of schedule or other conflicts. Standing meeting dates and the BPM appeals committee composition will be established at least three months in advance. The CAISO may change the meeting time with ten (10) Business Days notice if required to accommodate schedules of the members of the BPM appeals committee. The executive sponsor of a BPM PRR may not sit in review of any appeal of a final decision regarding that same BPM PRR but may participate in and be present during the public discussion of any appeal. The CAISO committee will review the appeal and publish its decision to the appealing party and to the CAISO Website. If not satisfied with the decision on appeal, the appellant may raise concerns it may have with the CAISO Governing Board at the next regularly scheduled ~~Board~~board meeting through the public comment period or through prior letter to the CAISO Governing Board.

* * *

24.~~10~~14.3.2 FPL Energy, LLC

Pursuant to its Project Sponsor status, consistent with FERC's findings in Docket No. ER03-407, issued on June 15, 2006 (115 FERC ¶ 61, 329), FPL Energy, LLC shall receive Merchant CRRs associated with transmission usage rights modeled for the Blythe Path 59 upgrade, such Merchant CRRs to be in effect for a period of thirty (30) years, or the pre-specified intended life of the Merchant Transmission Facility, whichever is less, from the date ~~of~~ Blythe Path 59 was energized. For the purpose of allocating Merchant CRRs to FPL Energy, LLC over the Blythe Path 59 upgrade, the allocation of CRR Option ~~CRRs~~ in the import (east to west, from the Blythe Scheduling Point to the 230 kV side of the 161 kV to 230 kV transformer at the Eagle Mountain substation) as well as of CRR Option ~~CRRs~~ in the export (west to east) direction will be based on 57.1 percent of the total upgrade (96 ~~MWs~~MW out of the 168 ~~MWs~~MW), which is FPL Energy, LLC's share of the total upgrade as approved by FERC in the ~~Letter Order~~letter order issued by FERC on June 15, 2006 in Docket No. ER03-407 (115 FERC ¶ 61,329).

* * *

25.1 Applicability

This Section 25 and Appendix U (the Standard Large Generator Interconnection Procedures (LGIP)), Appendix Y (the Generator Interconnection Procedures (LGIP) for Interconnection Requests in a Queue Cluster Window), Appendix S (the Small Generator Interconnection Procedures (SGIP)), or Appendix W, as applicable, shall apply to:

(a) each new Generating Unit that seeks to interconnect to the CAISO Controlled Grid;

(b) each existing Generating Unit connected to the CAISO Controlled Grid that will be modified with a resulting increase in the total capability of the power plant;

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

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

25.1.2 Affidavit Requirement

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

25.1.2.1 If the CAISO and the applicable Participating TO confirm that the electrical characteristics are substantially unchanged, then that request will not be placed into the interconnection queue. However, the owner of the ~~Qualifying Facility~~Generating Unit, or its designee, will be required to execute a Standard Large Generator Interconnection Agreement in accordance with Section 11 of Appendix U (the LGIP), a Large Generator Interconnection Agreement in accordance with Section 11 of Appendix Y (the GIP), a Small Generator Interconnection Agreement in accordance with Section 3.3.4, 3.4.5, or 3.5.7 and Section 4.8 of the SGIP, or an interconnection agreement in accordance with Appendix W, as applicable.

25.1.2.2 If the CAISO and the applicable Participating TO cannot confirm that the total capability and electrical characteristics are and will be substantially unchanged, then the owner of the ~~Qualifying Facility~~Generating Unit, or its designee, shall be an Interconnection Customer required to submit an Interconnection Request and comply with Appendix U (the LGIP), Appendix Y (the GIP), Appendix S (the SGIP), or Appendix W, as applicable.

* * *

26.5 Transition Mechanism

During the ten-year TAC Transition Period described in Section 4 of Schedule 3 of Appendix F, the Original Participating TOs collectively shall pay to the CAISO 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 of Appendix F. Responsibility for such payments shall be allocated to Original Participating TOs in accordance with Schedule 3 of 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 CAISO 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. At the conclusion of the ten-year TAC Transition Period, the obligations of this Section 26.5 shall cease to apply.

* * *

27.1.1 Locational Marginal Prices For Energy

~~The~~As further described in Appendix C, the LMP for Energy at any PNode is the marginal cost of serving the next increment of Demand at that PNode consistent with existing ~~transmission facility~~Transmission Constraints and the performance characteristics of resources~~. The LMPs calculated in the IFM, the HASP for Scheduling Points, and the RTD are based on~~, also considering, among other things, Energy Bid Curves. The LMP at any given PNode is comprised of three cost components: the System Marginal Energy Cost (SMEC); Marginal Cost of Losses (MCL); and Marginal Cost of Congestion (MCC). The IFM calculates LMPs for each Trading Hour of the next Trading Day. The HASP, which is ~~an~~conducted hourly ~~run of~~for scheduling Non-Dynamic System Resources and exports for the ~~RTUC with the Time Horizon that starts at the beginning of the next~~subsequent Trading Hour, calculates fifteen-minute LMPs (HASP Intertie LMPs) for that Trading Hour. The simple average of the four fifteen-minute LMPs for the applicable Trading Hour computed at each Scheduling Point produces hourly LMPs for HASP Settlement of Energy at that Scheduling Point. The Real-Time Dispatch runs every five (5) minutes throughout each

Trading Hour and calculates five-minute LMPs for the next Dispatch Interval. The CAISO uses the Resource-Specific Settlement Interval LMPs for Settlements of the Real-Time Market. In the event that a Pricing Node becomes electrically disconnected from the market model during a CAISO Market run, the LMP, including the SMEC, MCC and MCL, at the closest electrically connected Pricing Node will be used as the LMP at the affected location.

* * *

27.1.1.3 Marginal Cost of Congestion

The Marginal Cost of Congestion at a PNode reflects a linear combination of the Shadow Prices of ~~all~~the binding Transmission Constraints in the network,~~ each~~ multiplied by the corresponding Power Transfer Distribution Factor (PTDF). The Marginal Cost of Congestion may be positive or negative depending on whether a power injection (i.e., incremental Load increase) at that Location marginally increases or decreases Congestion.

* * *

27.1.2.1 Ancillary Service Marginal Prices – Sufficient Supply

As provided in Section 8.3, Ancillary Services are procured and awarded through the IFM, HASP and the Real-Time Market. The IFM calculates hourly Day-Ahead Ancillary Service Awards and establishes Ancillary Service Marginal Prices (ASMPs) for the accepted Regulation Up, Regulation Down, Spinning Reserve and Non-Spinning Reserve Bids. The IFM co-optimizes Energy and Ancillary Services subject to resource, network and regional constraints. In the HASP, the CAISO procures Ancillary Services from Non-Dynamic System Resources for the next Trading Hour as described in Section 33.7. The CAISO calculates the HASP settlement Ancillary Services price as described herein and further described in Section 33.8. In the Real-Time Market, the RTUC process that is performed every fifteen (15) minutes establishes fifteen (15) minute Ancillary Service Schedules, Awards, and prices for the upcoming quarter of the given Trading Hour. ASMPs are determined by first calculating Shadow Prices of Ancillary Services~~ procurement requirement Constraints~~ for each Ancillary Service type and the applicable Ancillary Services Regions. The Ancillary Services Shadow Prices are produced as a result of the co-optimization of Energy and Ancillary Services through the IFM, HASP, and the Real-Time Market, subject to resource, network, and requirement constraints. The Ancillary Services Shadow Prices represent the marginal cost of the relevant binding regional ~~Constraint~~constraints at the optimal solution, or the reduction of the combined Energy and Ancillary Service procurement cost associated with a marginal relaxation of that ~~Constraint~~constraint. If the ~~Constraint~~constraint for an Ancillary Services Region is not binding, the corresponding Ancillary Services Shadow Price in the Ancillary Services Region is zero (0). During periods in which supply is sufficient, the ASMP for a particular Ancillary Service type and Ancillary Services Region is then the sum of the Ancillary Services Shadow Prices for the specific type of Ancillary Service and all the other types of Ancillary Services for which the subject Ancillary Service can substitute, as described in Section 8.2.3.5, for the given Ancillary Service Region and all the other Ancillary Service Regions that include that given Ancillary Service Region. During periods in which supply is insufficient, the ASMP for a particular Ancillary Service type and Ancillary Services Region will reflect the Scarcity Reserve Demand Curve Values set forth in Section 27.1.2.3.

* * *

27.4.1 Security Constrained Unit Commitment

The CAISO uses SCUC to run the MPM-RRD processes associated with the DAM, the HASP, and the ~~HASP, the IFM, the RUC, the HASP, the STUC and the RTUC.~~RTM. SCUC ~~uses a multi-interval Time Horizon~~is conducted over multiple varying intervals to commit and schedule resources and to meet Demand for which Bids have been submitted and procure AS in the IFM, and to meet the CAISO Forecast of CAISO Demand in the MPM-RRD, RUC, HASP, STUC and RTUC. In the Day-Ahead MPM-RRD, IFM and RUC processes, the SCUC ~~optimizes~~commits resources over the twenty-four (24) hourly intervals of the next Trading Day. In the RTUC, which runs every fifteen (15) minutes and commits resources for the RTM, the SCUC optimizes over ~~from four to seven~~ a number of 15-minute intervals ~~comprising a portion of the current or imminent~~corresponding to the Trading Hours for which the Real-Time Markets have closed. The Trading Hours for which the Real-Time Markets have closed consist of (a) the Trading Hour ~~and~~in which the applicable run is conducted and (b) all the fifteen-minute intervals of the entire subsequent Trading Hour. In the HASP, which is a special run of the RTUC that runs once per hour ~~just before the top of the hour, and its associated MPM-RRD process, the SCUC optimizes over seven (7) 15-minute intervals comprising the last forty-five (45) minutes of the imminent Trading Hour and~~

~~the entire subsequent Trading Hour. Following the HASP run of the RTUC, each of the next three runs of the RTUC successively drops one 15-minute interval from the front of the optimization Time Horizon. In the STUC, the SCUC optimizes over seventeen fifteen-minute intervals comprising the of~~, the SCUC schedules Non-Dynamic System Resources and exports for the applicable subsequent Trading Hour. In the STUC, which runs once an hour, the SCUC commits resources over the last fifteen (15) minutes of the imminent Trading Hour and the entire next four Trading Hours. The CAISO will commit Extremely Long Start Resources, for which commitment in the DAM does not provide sufficient time to Start-Up and be available to supply Energy during the next Trading Day as provided in Section 31.7.

27.4.1.1 Timing of Unit Commitment Instructions

For the ~~Time Horizon~~applicable market intervals of any given CAISO Markets Process, the associated SCUC optimization will typically commit resources having different Start-Up Times, not all of which need to be started up immediately upon completion of that CAISO Markets Process. The CAISO may defer issuing a Start-Up Instruction to a resource that can be started at a later time and still be available to supply Energy at the time the CAISO Markets Process indicated it would be needed. The CAISO shall re-evaluate the need to commit such resources in a subsequent CAISO Markets Process based on the most recent forecasts and other information about system conditions.

27.4.2 Security Constrained Economic Dispatch

SCED is the optimization engine used to run the RTD to determine the optimal five-minute Dispatch Instructions throughout the Trading Hour consistent with resource constraints and ~~transmission~~Transmission Constraints within the CAISO Balancing Authority Area. ~~The SCED~~ In any given hour, the Real-Time Economic Dispatch of the Real-Time Market runs every five (5) minutes ~~and utilizes a Time Horizon comprised of up to thirteen (13) five-minute intervals, but~~ during which the SCED produces binding Dispatch Instructions ~~only~~ for the ~~first~~immediately subsequent five-minute interval ~~of that Time Horizon. The~~. For the applicable five-minute time period, through its SCED, the CAISO produces LMPs at each PNode that are used for Settlements as described in Section 11.5.

27.4.3 CAISO Markets Scheduling And Pricing Parameters

The SCUC and SCED optimization software for the CAISO Markets utilize a set of configurable scheduling and pricing parameters to enable the software to reach a feasible solution and set appropriate prices in instances where Effective Economic Bids are not sufficient to allow a feasible solution. The scheduling parameters specify the criteria for the software to adjust Non-priced Quantities when such adjustment is necessary to reach a feasible solution. The scheduling parameters are configured so that the SCUC and SCED software will utilize Effective Economic Bids as far as possible to reach a feasible solution, and will skip Ineffective Economic Bids and perform adjustments to Non-priced Quantities pursuant to the scheduling priorities for Self-Schedules specified in Sections 31.4 and 34.10. The scheduling parameters utilized for relaxation of internal ~~transmission constraints~~Transmission Constraints are specified in Section 27.4.3.1. The pricing parameters specify the criteria for establishing market prices in instances where one or more Non-priced Quantities are adjusted by the Market Clearing software. The pricing parameters are specified in Sections 27.1.2.3, 27.4.3.2, 27.4.3.3 and 27.4.3.4. The complete set of scheduling and pricing parameters used in all CAISO Markets is maintained in the Business Practice Manuals.

27.4.3.1 Scheduling Parameters for Transmission Constraint Relaxation

The internal ~~transmission~~Transmission Constraint scheduling parameter is set to $5000 per MWh for the purpose of determining when the SCUC and SCED software in the IFM and RTM will relax an internal ~~transmission constraint~~Transmission Constraint rather than adjust Supply or Demand bids or Non-priced Quantities as specified in Sections 31.3.1.3, 31.4 and 34.10 to relieve Congestion on the constrained facility. The effect of this scheduling parameter value is that if the optimization can re-dispatch resources to relieve Congestion on a ~~constrained transmission facility~~Transmission Constraint at a cost of $5000 per MWh or less, the Market Clearing software will utilize such re-dispatch, but if the cost exceeds $5000 per MWh the market software will relax the ~~constraint.~~Transmission Constraint. The corresponding scheduling parameter in RUC is set to $1250 per MWh.

27.4.3.2 Pricing Parameters for Transmission Constraint Relaxation

For the purpose of determining how the relaxation of a ~~transmission~~Transmission Constraint will affect the determination of prices in the IFM and RTM, the pricing parameter of the Transmission Constraint being relaxed is set to the maximum Energy Bid price specified in Section 39.6.1.1. The corresponding pricing parameter used in the RUC is set at the maximum RUC Availability Bid price specified in Section 39.6.1.2.

* * *

27.4.3.5 Protection of TOR, ETC and ~~CVR~~Converted Rights Self-Schedules in the IFM

In accordance with the submitted and accepted TRTC Instructions, valid Day-Ahead TOR Self-Schedules, Day-Ahead ETC Self-Schedules and Day-Ahead ~~CVR~~Converted Rights Self-Schedules shall not be adjusted in the IFM in response to an insufficiency of Effective Economic Bids. The scheduling parameters associated with the TOR, ETC, or ~~CVR~~Converted Rights Self-Schedules will be set to values higher than the scheduling parameter associated with relaxation of an internal ~~transmission~~Transmission Constraint as specified in Section 27.4.3.1, so that when there is a congested ~~transmission~~Transmission Constraint that would otherwise subject a Supply or Demand resource submitted in a valid and balanced ETC, TOR or ~~CVR~~Converted Rights Self-Schedule to adjustment in the IFM, the IFM software will relax the ~~transmission~~Transmission Constraint rather than curtail the TOR, ETC, or ~~CVR~~Converted Rights Self-Schedule. This priority will be adhered to by the operation of the IFM Market Clearing software, and if necessary, by adjustment of Schedules after the IFM has been executed and the results have been reviewed by the CAISO operators.

27.4.3.6 Effectiveness Threshold

The CAISO Markets software includes a lower effectiveness threshold setting which governs whether the software will consider a bid "effective" for managing congestion on a congested ~~constraint.~~Transmission Constraint. The CAISO will set this threshold at two (2) percent ~~(2%).~~.

* * *

27.5.1 Network Models used in CAISO Markets

The FNM is a representation of the WECC network model including the CAISO Balancing Authority Area that enables the CAISO to produce a Base Market Model that the CAISO then uses as the basis for formulating the individual market models used to conduct power flow analyses to manage ~~transmission~~ Transmission Constraints for the optimization of each of the CAISO Markets.

27.5.1.1 Base Market Model used in the CAISO Markets

Based on the FNM the CAISO creates the Base Market Model (BMM), which is used as the basis for formulating, as described in section 27.5.6, the individual market models used in each of the CAISO Markets to establish, enforce, and manage the ~~transmission~~Transmission Constraints associated with network facilities. The Base Market Model is derived from the FNM by (1) introducing locations for modeling intertie schedules; and (2) introducing market resources that do not currently exist in the FNM due to their size and lack of visibility. In the Base Market Model, External Balancing Authority Areas and external transmission systems are modeled to the extent necessary to support the commercial requirements of the CAISO Markets. For those portions of the FNM that are external to the CAISO Balancing Authority Area, the Base Market Model may model the resistive component for accurate modeling of Transmission Losses, but accounts for losses in the external portions of the market model separately from Transmission Losses within the CAISO Balancing Authority Area. As a result the Marginal Cost of Losses in the LMPs is not affected by external losses. For portions of the Base Market Model that are external to the CAISO Balancing Authority Area, the CAISO Markets only enforce ~~network~~Transmission Constraints that reflect limitations of the transmission facilities and Entitlements turned over to the Operational Control of the CAISO by a Participating Transmission Owner, or that affect Congestion Management within the CAISO Balancing Authority Area or on Interties. External connections are retained between Intertie branches within Transmission Interfaces. Certain external loops are modeled, which allows the CAISO to increase the accuracy of the Congestion Management process. Resources are modeled at the appropriate network Nodes.

The pricing Location (PNode) of a Generating Unit generally coincides with the Node where the relevant revenue quality meter is connected or corrected, to reflect the point at which the Generating Units are connected to the CAISO Controlled Grid. The Dispatch, Schedule, and LMP of a Generating Unit refers to a PNode, but the Energy injection is modeled in the Base Market Model for network analysis purposes at the corresponding Generating Unit's physical interconnection point), taking into account any losses in the non-CAISO Controlled Grid leading to the point where Energy is delivered to CAISO Controlled Grid.. Based on the BMM, the market models used in each of the CAISO markets incorporate physical characteristics needed for determining Transmission Losses and model ~~network~~Transmission Constraints within the CAISO Balancing Authority Area, which are then reflected in the Day-Ahead Schedules, AS Awards and RUC Awards, HASP Intertie Schedules, Dispatch Instructions and the LMPs resulting from each CAISO Markets Process. Further, in formulating the market models for the HASP, STUC, RTUC and the RTD processes, the Real-Time power flow parameters developed from the State Estimator are applied to the Base Market Model.

* * *

27.5.2 Metered Subsystems

The FNM includes a full model of MSS transmission networks used for power flow calculations and Congestion Management in the CAISO Markets Processes. ~~Network~~Transmission Constraints (i.e. circuit ratings, thermal ratings, etc.) within the MSS, or at its boundaries, that are modeled in the ~~{~~Base Market Model~~}~~ shall be monitored but not enforced in operation of the CAISO Markets. If overloads are observed in the forward markets, are internal to the MSS or at the MSS boundaries, and are attributable to MSS operations, the CAISO shall communicate such events to the Scheduling Coordinator for the MSS and coordinate any manual Re-dispatch required in Real-Time. If, independent of the CAISO, the Scheduling Coordinator for the MSS is unable to resolve Congestion internal to the MSS or at the MSS boundaries in Real-Time, the CAISO will use Exceptional Dispatch Instructions on resources that have been bid into the HASP and RTM to resolve the Congestion. The costs of such Exceptional Dispatch will be allocated to the responsible MSS Operator. Consistent with Section 4.9, the CAISO and MSS Operator shall develop specific procedures for each MSS to determine how ~~network~~Transmission Constraints will be handled.

27.5.3 Integrated Balancing Authority Areas

To the extent sufficient data are available or adequate estimates can be made for an IBAA, the Base Market Model used by the CAISO for the CAISO Markets Processes will include a model of the IBAA's network topology. The CAISO monitors but does not enforce the ~~network~~Transmission Constraints for an IBAA in running the CAISO Markets Processes. Similarly, the CAISO models the resistive component for transmission losses on an IBAA but does not allow such losses to determine LMPs that apply for pricing transactions to and from an IBAA and the CAISO Balancing Authority Area, unless allowed under a Market Efficiency Enhancement Agreement. For Bids and Schedules between the CAISO Balancing Authority Area and the IBAA, the CAISO will model the associated sources and sinks that are external to the CAISO Balancing Authority Area using individual or aggregated injections and withdrawals at locations in the FNM that allow the impact of such injections and withdrawals on the CAISO Balancing

Authority Area to be reflected in the CAISO Markets Processes as accurately as possible given the information available to the CAISO.

27.5.5 Load Distribution Factors

The CAISO will maintain a library of system-wide Load Distribution Factors for use in distributing Demand scheduled at the Default LAPs. The system Load Distribution Factors are derived from the State Estimator and are stored in the Load Distribution Factor library, and are updated periodically. For IFM the Load Distribution Factor library uses a similar-day methodology for smoothing the most recent Load Distribution Factors. The similar-day methodology uses data separately for each type of day. More recent days are weighted more heavily in the smoothing calculations. The market application then uses the set of Load Distribution Factors from the library that best represents the Load distribution conditions expected for use in the ~~market Time Horizon~~CAISO Market Processes. For the RTM, the State Estimator solution is used as a source for determining Load Distribution Factors. The Load Distribution Factor are also maintained for use for Demand scheduled at Custom LAPs. These custom Load Distribution Factors are not generated from the State Estimator and are fixed quantities representing the characteristics of the Custom LAP.

* * *

27.5.6 Management & Enforcement of Constraints in the CAISO Markets

The CAISO operates the CAISO Markets through the use of a market software system that utilizes various information including the Base Market Model, the State Estimator, submitted Bids including Self-Schedules, Generated Bids, and ~~transmission~~Transmission Constraints, including Nomograms and Contingencies transmission and generation Outages. The market model used in each of the CAISO Markets is derived from the most current Base Market Model available at that time. To create a more relevant time-specific network model for use in each of the CAISO Markets, the CAISO will adjust the Base Market Model to reflect Outages and derates that are known and applicable when the respective CAISO Market will operate, and to compensate for observed discrepancies between actual real-time power flows and flows calculated by the market software. Through this process the CAISO creates the market model to be used in each Day-Ahead Market, HASP, and each process of the Real-Time Market. The CAISO will manage the enforcement of ~~transmission~~Transmission Constraints, including Nomograms and Contingencies, consistent with good utility practice, to ensure, to the extent possible, that the market model used in each market accurately reflects all the factors that contribute to actual Real-Time flows on the CAISO Controlled Grid and that the CAISO Market results are better aligned with actual physical conditions on the CAISO Controlled Grid. In operating the CAISO Markets, the CAISO may take the following actions so that, to the extent possible, the CAISO Market solutions are feasible, accurate, and consistent with good utility practice:

(a) The ISO may enforce, not enforce, or adjust flow-based ~~transmission~~Transmission Constraints, including Nomograms and Contingencies, if the CAISO observes that the CAISO Markets produce or may produce results that are inconsistent with observed or reasonably anticipated conditions or infeasible market solutions either because (a) the CAISO reasonably anticipates that the CAISO Market run will identify Congestion that is unlikely to materialize in Real-Time even if the ~~transmission~~Transmission Constraint were to be ignored in all the markets leading to Real-Time, or (b) the CAISO reasonably anticipates that the CAISO Market will fail to identify Congestion that is likely to appear in the Real-Time. The ISO does not make such adjustments to intertie Scheduling Limits.

(b) The ISO may enforce or not enforce ~~transmission~~Transmission Constraints, including Nomograms and Contingencies, if the CAISO has determined that non-enforcement or enforcement, respectively, of such Constraints may result in the unnecessary pre-commitment and scheduling of use-limited resources.

(c) The CAISO may not enforce ~~transmission~~Transmission Constraints, including Nomograms and Contingencies, if it has determined it lacks sufficient visibility to conditions on transmission facilities necessary to reliably ascertain ~~Constraint~~constraint flows required for a feasible, accurate and reliable market solution.

(d) For the duration of a planned or unplanned Outage, the CAISO may create and apply alternative ~~transmission~~Transmission Constraints, including Nomograms and Contingencies, that may add to or replace certain originally defined ~~Constraints.}~~constraints.

(e) The CAISO may adjust ~~transmission~~Transmission Constraints, including Nomograms and Contingencies, for the purpose of setting prudent operating margins consistent with good utility practice to ensure reliable operation under anticipated conditions of unpredictable and uncontrollable flow volatility consistent with the requirements of Section 7.

To the extent that particular ~~transmission~~Transmission Constraints, including Nomograms and Contingencies, are not enforced in the operations of the CAISO Markets, the CAISO will operate the CAISO Controlled Grid and manage any Congestion based on available information including the State Estimator solutions and available telemetry to Dispatch resources through Exceptional Dispatch to ensure the CAISO is operating the CAISO Controlled Grid consistent with the requirements of Section 7.

* * *

27.7.5 Constrained Output Generators In The Real-Time Market

A COG that can be started up and complete its Minimum Run Time within a five-hour period can be committed by the STUC. A COG that can be started up within the ~~Time Horizon of a~~applicable RTUC run as described in Section 34.2 can be committed by the RTUC. The RTD will dispatch a COG up to its PMax or down to zero (0) to ensure a feasible Real-Time Dispatch. The COG is eligible to set the RTM LMP in any Dispatch Interval in which a portion of its output is needed to serve Demand, not taking into consideration its Minimum Run Time constraint. For the purpose of making this determination and setting the RTM LMP, the CAISO treats a COG as if it were flexible with an infinite Ramp Rate between zero (0) and its PMax, and uses the COG's Calculated Energy Bid. In any Dispatch Interval where none of the output of a COG is needed as a flexible resource to serve Demand, the CAISO shall not dispatch the unit. In circumstances in which the output of the COG is not needed as a flexible resource to serve Demand, but the unit nonetheless is online as a result of a previous commitment or Dispatch Instruction by the CAISO, the COG is eligible for Minimum Load Cost compensation.

* * *

28.3.1 Information Requirements

An Inter-SC Trade of IFM Load Uplift Obligation shall contain the following information: (i) the Scheduling Coordinator ~~identification~~ID Code for the Scheduling Coordinator from whom the MW amounts of IFM Load Uplift Obligation is traded; (ii) the Scheduling Coordinator ~~identification~~ID Code for the Scheduling Coordinator to whom the MW amounts of IFM Load Uplift Obligation is traded; (iii) the applicable Location of the Inter-SC Trade of IFM Load Uplift Obligation; (iv) the time period over which the trade will take place, including the start-date and time and the end-date and time; and (v) the quantity (MW) of the IFM Load Uplift Obligation to be traded.

* * *

30.5.2.1 Common Elements for Supply Bids

In addition to the resource-specific Bid requirements of this Section, all Supply Bids must contain the following components: Scheduling Coordinator ID Code; Resource ~~ID and the~~Location or Resource ID, as appropriate; MSG Configuration ID, as applicable~~; Resource Location~~; PNode or Aggregated Pricing Node as applicable; Energy Bid Curve; Self-Schedule component; Ancillary Services Bid; RUC Availability

Bid; as applicable, the Market to which the Bid applies; Trading Day to which the Bid applies; Priority Type (if any). Supply Bids offered in the CAISO Markets must be monotonically increasing. Energy Bids in the RTM must also contain a Bid for Ancillary Services to the extent the resource is certified and capable of providing Ancillary Service in the RTM up to the registered certified capacity for that Ancillary Service less any Day-Ahead Ancillary Services Awards.

Scheduling Coordinators must submit the applicable Supply Bid components, including Self-Schedules, for the submitted MSG Configuration.

30.5.2.2 Supply Bids for Participating Generators

In addition to the common elements listed in Section 30.5.2.1, Supply Bids for Participating Generators shall contain the following components as applicable: Start-Up Bid, Minimum Load Bid, Ramp Rate, Minimum and Maximum Operating Limits; Energy Limit, Regulatory Must-Take/Must-Run Generation; Contingency Flag; and Contract Reference Number (if any). Scheduling Coordinators submitting these Bid components for a Multi-Stage Generating Resource must do so for the submitted MSG Configuration. A Scheduling Coordinator for a Physical Scheduling Plant or a System Unit may include Generation Distribution Factors as part of its Supply Bid. If the Scheduling Coordinator has not submitted the Generation Distribution Factors applicable for the Bid, the CAISO will use default Generation Distribution Factors stored in the Master File. All Generation Distribution Factors used by the CAISO will be normalized based on Outage data that is available to the automated market systems. A Multi-Stage Generating Resource and its MSG Configurations are registered under a single Resource ID and Scheduling Coordinator for the Multi-Stage Generating Resource must submit all Bids for the resource's MSG Configurations under the same Resource ID. For a Multi-Stage Generating Resources Scheduling Coordinators may submit bid curves for up to ten individual MSG Configurations of their Multi-Stage Generating Resources into the Day-Ahead Market and up to three individual MSG Configurations into the Real-Time Market. Scheduling Coordinators for Multi-Stage Generating Resources must submit a single Operational Ramp Rate for each MSG Configuration for which it submits a supply Bid either in the Day-Ahead Market or Real-Time Market. For Multi-Stage Generating Resources the Scheduling Coordinator may submit the Transition Times, which cannot be greater than the maximum Transition Time registered in the Master File. To the extent the Scheduling Coordinator does not submit the Transition Time that is a registered feasible transition the CAISO will use the registered maximum Transition Time for that MSG Transition for the specific Multi-Stage Generating Resource.

* * *

30.5.2.7 RUC Availability Bids

Scheduling Coordinators may submit RUC Availability Bids for specific Generating Units capacity that is not Resource Adequacy Capacity or ICPM Capacity of in the DAM~~; however,~~. Scheduling Coordinators for Resource Adequacy Capacity or ICPM Capacity must participate in RUC to the extent that such capacity is not reflected in an IFM Schedule but need not submit RUC Availability Bids~~ for that capacity to the extent that the capacity has not been submitted in~~ , Resource Adequacy Capacity participating in RUC will be optimized using a ~~Self-Schedule or already been committed to provide Energy or capacity in the IFM~~zero dollar ($0/MW-hour) RUC Availability Bid. For Multi-Stage Generating Resources the RUC Availability Bids shall be submitted at the MSG Configuration. Capacity that does not have Bids for Supply of Energy in the IFM will not be eligible to participate in the RUC process. The RUC Availability Bid component is MW-quantity of non-Resource Adequacy Capacity in $/MW per hour~~, and $0/MW for Resource Adequacy Capacity or ICPM Capacity~~.

* * *

30.5.3 Demand Bids

Each Scheduling Coordinator representing Demand, including Non-Participating Load and Aggregated Participating Load, shall submit Bids indicating the hourly quantity of Energy in MWh that it intends to purchase in the IFM for each Trading Hour of the Trading Day. Scheduling Coordinators must submit Demand Bids, including Self Schedules, for CAISO Demand at Load Aggregation Points except as provided in Section 30.5.3.2.~~ Scheduling Coordinators must submit a zero RUC Availability Bid for the portion of their qualified Resource Adequacy Capacity. If submitting Self-Schedules at Scheduling Points for export in the IFM, the Scheduling Coordinator shall indicate whether or not the export is served from Generation from Resource Adequacy Capacity, and if submitting Self-Schedules at Scheduling Points for export in HASP the Scheduling Coordinator shall indicate whether or not the export is served from Generation from Resource Adequacy Capacity or RUC Capacity. The procedure for identifying the non-Resource Adequacy Capacity or non-RUC Capacity is specified in the Business Practice Manuals.~~

30.5.3.1 Demand Bids Components

Demand Bids must have the following components: Scheduling Coordinator ID ~~code~~Code; a Demand Bid curve that is a monotonically decreasing staircase function of no more than ten (10) segments defined by eleven (11) ordered pairs of MW and $/MWh; Location Code for the LAP, Custom LAP or PNode, as applicable; and hourly scheduled MWh within the range of the Bid curve, including any zero values, for each Settlement Period of the Trading Day.

* * *

30.7.3.1 Validation Prior to Market Close and Master File Update

The CAISO conducts Bid validation in three steps as described below. For a Multi-Stage Generating Resource the validation described herein is done for each submitted MSG Configuration.

Step 1: The CAISO will validate all Bids after submission of the Bid for content validation which determines that the Bid adheres to the structural rules required of all Bids as further described in the Business Practices Manuals. If the Bid fails any of the content level rules the CAISO shall assign it a rejected status and the Scheduling Coordinator must correct and resubmit the Bid.

Step 2: After the Bids are successfully validated for content, but prior to the Market Close of the DAM, the Bids will continue through the second level of validation rules to verify that the Bid adheres to the applicable CAISO Market rules and if applicable, limits based on Master File data. If the Bid fails any level two validation rules, the CAISO shall assign the Bid as invalid and the Scheduling Coordinator must either correct or resubmit the Bid.

Step 3: If the Bid successfully passes validation in Step 2, it will continue through the third level of validation where the Bid will be analyzed based on its contents to identify any missing Bid components that must be either present for the Bid to be valid consistent with the market rules contained in Article III of this CAISO Tariff and as reflected in the Business Practice Manuals. At this stage the Bid will either be automatically modified for correctness and assigned a status of conditionally modified or modified, or if it can be accepted as is, the Bid will be assigned a status of conditionally valid, or valid. A Bid will be automatically modified and assigned a status of modified or conditionally modified Bid, whenever the CAISO inserts or modifies a Bid component. The CAISO will insert or modify a Bid component whenever

(1) a Self-Schedule quantity is less than the lowest quantity specified as an Economic Bid for either an Energy Bid or Demand Bid, in which case the CAISO extends the Self-Schedule to cover the gap; (2) for non-Resource Adequacy Resources, the CAISO will extend the Energy Bid Curve using Proxy Costs to cover any capacity in a RUC Bid component, if necessary; and (3) for a Resource Adequacy Resource that is not a Use-Limited Resource, the CAISO will extend the Energy Bid Curve using Proxy Costs to cover any capacity in a RUC Bid component and, if necessary, up to the full registered Resource Adequacy Capacity. The CAISO will generate a Proxy Bid or extend an Energy Bid or Self-Schedule to cover any RUC Award or Day-Ahead Schedule in the absence of any Self-Schedule or Economic Bid components, or to fill in any gaps between any Self-Schedule Bid and any Economic Bid components to cover a RUC Award or Day-Ahead Schedule. To the extent that an Energy Bid to the HASP/RTM is not accompanied by an Ancillary Services Bid, the CAISO will insert a Spinning Reserve and Non-Spinning Reserve Ancillary Services Bid at $ 0/MW for any certified Operating Reserve capacity. The CAISO will also generate a Self-Schedule Bid for any Generating Unit that has a Day-Ahead Schedule but has not submitted Bids in HASP/RTM, up to the quantity in the Day-Ahead Schedule. Throughout the Bid evaluation process, the Scheduling Coordinator shall have the ability to view the Bid and may choose to cancel the Bid, modify and re-submit the Bid, or leave the modified, conditionally modified or valid, conditionally valid Bid as is to be processed in the designated CAISO Market. The CAISO will not insert or extend any Bid for Regulation Up or Regulation Down in the Real-Time Market for a ~~Resource Adequacy Resource that is a~~ Use-Limited Resource except as provided in Section 40.6.8. The CAISO will not insert or extend a Spinning Reserve or Non-Spinning Reserve Ancillary Service Bid at $0 in the Real-Time Market for any certified Operating Reserve capacity of a resource unless that resource submits an Energy Bid and fails to submit an Ancillary Service Bid in the Real-Time Market.

* * *

30.7.6.1 Validation of Ancillary Services Bids

Throughout the validation process described in Section 30.7, the CAISO will verify that each Ancillary Services Bid conforms to the content, format and syntax specified for the relevant Ancillary Service. If the Ancillary Services Bid does not so conform, the CAISO will send a notification to the Scheduling Coordinator notifying the Scheduling Coordinator of the errors in the Bids as described in Section 30.7.

When the Bids are submitted, a technical validation will be performed to verify that the bid quantity of Regulation, Spinning Reserve, or Non-Spinning Reserve does not exceed the certified Ancillary Services capacity for Regulation, or Operating Reserves on the Generating Units, System Units, Participating Loads, Proxy Demand Resources, and external imports/exports bid. The Scheduling Coordinator will be notified within a reasonable time of any validation errors. For each error detected, an error message will be generated by the CAISO in the Scheduling Coordinator's notification screen, which will specify the nature of the error. The Scheduling Coordinator can then look at the notification messages to review the detailed list of errors, make changes, and resubmit if it is still within the CAISO's timing requirements. The Scheduling Coordinator is also notified of successful validation. If a resource is awarded or has qualified Self-Provided Ancillary Services in the Day-Ahead Market, if no Energy Bid is submitted to cover the awarded or Self-Provided Ancillary Services by the Market Close of HASP and the RTM, the CAISO will generate or extend an Energy Bid as necessary to cover the awarded or Self-Provided Ancillary Services capacity using the registered values in the Master File and relevant fuel prices as described in the Business Practice Manuals for use in the HASP and IFM. If an AS Bid or Submission to Self-Provide an AS is submitted in the Real-Time Market for Spinning Reserve or Non-Spinning Reserve without an accompanying Energy Bid at all, the AS Bid or Submission to Self-Provide an Ancillary Service will be erased. If an AS Bid ~~or Submission to Self-Provide an AS~~ is submitted in the HASP or Real-Time Market for Spinning Reserve and Non-Spinning Reserve with only a partial Energy Bid for the AS capacity, the CAISO will generate an Energy Bid for the uncovered portions. If a Submission to Self-Provide an Ancillary Service is submitted in the HASP or Real-Time Market for Spinning Reserve and Non-Spinning Reserve with only a partial Energy Bid for the AS capacity bid in, the CAISO will not generate or extend an Energy Bid for the uncovered portions. For Generating Units with certified Regulation capacity, if there no Bid for Regulation in the Real-Time Market, but there is a Day-Ahead award for Regulation Up or Regulation Down or a submission to self-provide Regulation Up or Regulation Down, respectively, the CAISO will generate a Regulation Up or Regulation Down Bid at the default Ancillary Service Bid price of $0 up to the certified Regulation capacity for the Generating Unit minus any Regulation awarded or self-provided in the Day-Ahead. If there is a Bid for Regulation Up or Regulation Down in the Real-Time Market, the CAISO will increase the respective Bid up to the certified Regulation capacity for the

Generating Unit minus any Regulation awarded or self-provided in the Day-Ahead. If a Self-Schedule amount is greater than the Regulation Limit for Regulation Up, the Regulation Up Bid will be erased.

Notwithstanding any of the provisions of Section 30.7.6.1 set forth above, the CAISO will not insert or extend any Bid for ~~a Resource Adequacy Resource that is a Use-Limited Resource~~Regulation Up or Regulation Down in the Real-Time Market for a Use-Limited Resource except as provided in Section 40.6.8. The CAISO will not insert a Spinning Reserve and Non-Spinning Reserve Ancillary Service Bid at $0 in the Real-Time Market for any certified Operating Reserve capacity of a resource unless that resource submits an Energy Bid but fails to submit an Ancillary Service Bid in the Real-Time Market.

30.7.6.2 Treatment of Ancillary Services Bids

When Scheduling Coordinators bid into the Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve markets, they may submit Bids for the same capacity into as many of these markets as desired at the same time by providing the appropriate Bid information to the CAISO. The CAISO optimization will evaluate AS Bids simultaneously with Energy Bids. A Scheduling Coordinator may specify that its Bid applies only the markets it desires. A Scheduling Coordinator shall also have the ability to specify different capacity prices for the Spinning Reserve, Non-Spinning Reserve, and Regulation markets. A Scheduling Coordinator providing one or more Regulation Up, Regulation Down, Spinning Reserve or Non-Spinning Reserve services may not change the identification of the Generating Units or Proxy Demand Resources offered in the Day-Ahead Market or in the Real-Time Market for such services unless specifically approved by the CAISO (except with respect to System Units, if any, in which case Scheduling Coordinators are required to identify and disclose the resource specific information for all Generating Units~~.~~, Participating Loads, and Proxy Demand Resources constituting the System Unit for which Bids and Submissions to Self-Provide Ancillary Services are submitted into the CAISO's Day-Ahead Market and Real-Time Market).

The following principles will apply in the treatment of Ancillary Services Bids in the CAISO Markets:

(a) not differentiate between bidders for Ancillary Services and Energy other than through cost, price, effectiveness, and capability to provide the Ancillary Service or Energy, and the required locational mix of Ancillary Services;

(b) select the bidders with most cost effective Bids for Ancillary Service capacity which meet its technical requirements, including location and operating capability to minimize the costs to users of the CAISO Controlled Grid;

(c) evaluate the Day-Ahead Bids over the twenty-four (24) Settlement Periods of the following Trading Day along with Energy, taking into ~~transmission constraints~~account Transmission Constraints and AS Regional Limits;

(d) evaluate Import Bids along with internal resources;

(e) establish Real-Time Ancillary Service Awards through RTUC from imports and resources internal to the CAISO Balancing Authority Area at fifteen (15) minutes intervals to the hour of operation; and

(f) procure sufficient Ancillary Services in the Day-Ahead and Real-Time Markets to meet its forecasted requirements.

* * *

31.1 Bid Submission And Validation In The Day-Ahead Market

Bids, including Self-Schedules and Ancillary Services Bids, and Submissions to Self-Provide an Ancillary Service shall be submitted pursuant to the submission rules specified in Section 30. There is a single bid submission in which Scheduling ~~Coordinators submit a single Bid to be~~Coordinators' Bids are used ~~in~~for purposes of the DAM, which includes the MPM-RRD, the IFM and RUC. Scheduling Coordinators may submit Bids for the DAM as early as seven (7) days ~~ahead of~~prior to the ~~targeted DAM and~~applicable Trading Day up to Market Close of the DAM for ~~a targeted~~the applicable Trading Day. The CAISO will validate all Bids submitted to the DAM pursuant to the procedures set forth in Section 30.7. Scheduling Coordinators must submit Bids for participation in the IFM for Resource Adequacy Capacity as required in Section 40.

* * *

31.2.1 The Reliability And Market Power Mitigation Runs

The first run of the MPM-RRD procedures is the Competitive Constraints Run (CCR), in which only limits on transmission lines pre-designated as competitive are enforced. The only RMR Units considered in the

CCR are Condition 1 RMR Units that have provided market Bids for the DAM and Condition 2 RMR Units when obligated to submit a Bid pursuant to an RMR Contract. The second run is the All Constraints Run (ACR), during which all ~~transmission~~Transmission Constraints that are expected to be enforced in the Integrated Forward Market are enforced. All RMR Units, Condition 1 and Condition 2, are considered in the ACR.

* * *

31.3 Integrated Forward Market

After the MPM-RRD and prior to RUC, the CAISO shall perform the IFM. The IFM (1) performs Unit Commitment and Congestion Management (2) clears mitigated or unmitigated Bids cleared in the MPM-RRD as well as Bids that were not cleared in the MPM-RRD process against bid-in Demand, taking into account transmission limits and honoring technical and inter-temporal operating ~~Constraints~~constraints, such as Minimum Run Times (3) and procures Ancillary Services to meet one hundred (100) percent ~~(100%)~~ of the CAISO Forecast of CAISO Demand requirements. The IFM utilizes a set of integrated programs that: (1) determine Day-Ahead Schedules and AS Awards, and related LMPs and ASMPs; and (2) optimally commits resources that are bid in to the DAM. The IFM utilizes a SCUC algorithm that optimizes Start-Up Costs, Minimum Load Costs, Transition Costs, and Energy Bids along with any Bids for Ancillary Services as well as Self-Schedules submitted by Scheduling Coordinators. The IFM selects the optimal MSG Configuration from a maximum of ten MSG Configurations of each Multi-Stage Generating Resource as mutually exclusive resources. If a Scheduling Coordinator submits a Self-Schedule or a Submission to Self-Provide Ancillary Services for a given MSG Configuration in a given Trading Hour, the IFM will consider the Start-Up Cost, Minimum Load Cost, and Transition Cost associated with any Economic Bids for other MSG Configurations as incremental costs between the other MSG Configurations and the self-scheduled MSG Configuration. In such cases, incremental costs are the additional costs incurred to transition or operate in an MSG Configuration in addition to the costs associated with the self-scheduled MSG Configuration. The IFM also provides for the optimal management of Use-Limited Resources. The ELS Resources committed through the ELC Process conducted two days before the day the IFM process is conducted for the next Trading Day as described in Section 31.7 are binding.

* * *

31.3.1.3 Reduction of Self-Scheduled LAP Demand

In the IFM, to the extent the market software cannot resolve a non-competitive ~~transmission~~Transmission Constraint utilizing Effective Economic Bids such that ~~Self-Scheduled~~self-scheduled Load at the LAP level would otherwise be reduced to relieve the Transmission Constraint, the CAISO Market software will adjust Non-priced Quantities in accordance with the process and criteria described in Section 27.4.3. For this purpose the priority sequence, starting with the first type of Non-priced Quantity to be adjusted, will be: (a) Schedule the Energy from Self-Provided Ancillary Service Bids from capacity that is obligated to offer an Energy Bid under a must-offer obligation such as from an RMR Unit or a Resource Adequacy Resource. Consistent with Section 8.6.2, the CAISO Market software could also utilize the Energy from Self-Provided Ancillary Service Bids from capacity that is not under a must-offer obligation such as from an RMR Unit or a Resource Adequacy Resource, to the extent the Scheduling Coordinator has submitted an Energy Bid for such capacity. The associated Energy Bid prices will be those resulting from the MPM-RRD process.(b) Relax the ~~Constraint~~constraint consistent with Section 27.4.3.1, and establish prices consistent with Section 27.4.3.2. No constraints, including Transmission Constraints, on Interties with adjacent ~~Balance~~Balancing Authority Areas will be relaxed in this procedure.

* * *

31.3.3 Metered Subsystems

In clearing the IFM, the CAISO will not enforce Transmission Constraints within each MSS. The Full Network Model (FNM) includes a full model of MSS transmission networks used for power flow calculations and Transmission Constraint management in the IFM and RTM. ~~Network~~Transmission Constraints (i.e. circuit ratings, thermal ratings, etc.) within the MSS, or at its boundaries, that are modeled in the FNM shall be monitored but not enforced in the operation of the CAISO Markets. If overloads are observed in the forward markets that are internal to the MSS or at the MSS boundaries and are attributable to MSS operations, the CAISO shall communicate such events to the Scheduling Coordinator for the MSS and coordinate any manual Re-dispatch required in Real-Time. If, independent of the CAISO, the Scheduling Coordinator for the MSS is unable to resolve Congestion internal to the MSS or at the MSS boundaries in Real-Time, the CAISO will use Exceptional Dispatch Instructions on resources that have been bid into the HASP and RTM to resolve the Congestion. Such costs will be allocated pursuant to the provisions specified in Section 11.5.6.2.5.2. The CAISO and MSS Operator shall develop specific procedures for each MSS to determine how ~~network~~Transmission Constraints will be handled. Costs associated with internal Congestion and Transmission Losses in the MSS will be the responsibility of the MSS Operator. The Scheduling Coordinator for the MSS shall be responsible for payment of Marginal Losses for transactions at any points of interconnection between the MSS and the CAISO Controlled Grid, and for the delivery of Energy to the MSS or from the MSS in accordance with the CAISO Tariff. For MSS Operators that elect Load following, the CAISO shall exclude the effect of Transmission Losses in the relevant MSS in the CAISO's calculation of loss sensitivity factors used to calculate LMPs.

31.4 CAISO Market Adjustments To Non-Priced Quantities In The IFM

All Self-Schedules are respected by SCUC to the maximum extent possible and are protected from curtailment in the Congestion Management process to the extent that there are Effective Economic Bids that can relieve Congestion. If all Effective Economic Bids in the IFM are exhausted, resource Self-Schedules between the resource's Minimum Load and the first Energy level of the first Energy Bid point will be subject to adjustments by the CAISO Market ~~Optimization~~optimization based on the scheduling priorities listed below. This functionality of the optimization software is implemented through the setting of scheduling parameters as described in Section 27.4.3 and specified in Section 27.4.3.1 and the ~~BPMs.~~Business Practice Manuals. Through this process, imports and exports may be reduced to zero, Demand Bids may be reduced to zero, Price Taker Demand (LAP load) may be reduced, and Generation may be reduced to a lower operating limit (or Regulation Limit) (or to a lower Regulation Limit plus any qualified Regulation Down award or Self-Provided Ancillary Services, if applicable). Any Self-Schedules below the Minimum Load level are treated as fixed Self-Schedules and are not subject to these adjustments for Congestion Management. The provisions of this section shall apply only to the extent they do not conflict with any MSS Agreement. In accordance with Section 27.4.3.5 the resources submitted in valid TOR, ETC or ~~CVR~~Converted Rights Self-~~Schedule~~Schedules shall not be adjusted in the IFM in response to an insufficiency of Effective Economic Bids. Thus the adjustment sequence for the IFM from highest priority (last to be adjusted) to lowest priority (first to be adjusted), is as follows:

(a) Reliability Must Run (RMR) Generation pre-dispatch reduction;

(b) Day-Ahead TOR Self-Schedules reduction (balanced demand and supply reduction);

(c) Day-Ahead ETC and ~~CVR~~Converted Rights Self-~~Schedule~~Schedules reduction; different ETC priority levels will be observed based upon global ETC priorities provided to the CAISO by the Responsible PTOs;

(d) Internal ~~transmission~~Transmission Constraint relaxation for the IFM pursuant to Section 27.4.3.1;

(e) Other Self-Schedules of CAISO Demand reduction subject to Section 31.3.1.3, exports explicitly identified in a Resource Adequacy Plan to be served by Resource Adequacy Capacity explicitly identified and linked in a Supply Plan to the exports, and Self-Schedules of exports at Scheduling Points explicitly sourced by non-Resource Adequacy Capacity;

(f) Self-Schedules of exports at Scheduling Points not explicitly sourced by non-Resource Adequacy Capacity, except those exports explicitly identified in a Resource Adequacy Plan to be served by Resource Adequacy Capacity explicitly identified and linked in a Supply Plan to the exports as set forth in Section 31.4(d);

(g) Day-Ahead Regulatory Must-Run Generation and Regulatory Must-Take Generation reduction;

(h) Other Self-Schedules of Supply reduction.

* * *

31.5.1.2 RUC Availability Bids

Scheduling Coordinators may only submit RUC Availability Bids for capacity (above the Minimum Load) for which they are also submitting an Energy Bid to participate in the IFM. ~~The RUC Availability Bid for the Resource Adequacy Capacity submitted by a Scheduling Coordinator must be $0/MW per hour for the entire Resource Adequacy Capacity. If the Scheduling Coordinator fails to submit a $0/MW per hour for~~

~~Resource Adequacy Capacity, the CAISO will insert the $0/MW per hour for the full amount of Resource Adequacy Capacity for a given resource reduced by any upward Ancillary Services Awards.~~Any available Resource Adequacy Capacity and ICPM Capacity will be optimized at $0/MW in RUC. For Multi-Stage Generating Resources that fail to submit a $0/MW per hour for the Resource Adequacy Capacity, the CAISO will insert the $0/MW per hour for the resource's Resource Adequacy Capacity at the MSG Configuration level up to the minimum of the Resource Adequacy Capacity or the PMax of the MSG Configuration. Scheduling Coordinators may submit non-zero RUC Availability Bids for the portion of a resource's capacity that is not Resource Adequacy Capacity~~.~~ or ICPM Capacity.

31.5.4 RUC Procurement Constraints

In addition to the resource ~~Constraints~~constraints and ~~network~~Transmission Constraints employed by SCUC as discussed in Section 27.4.1, the CAISO shall employ the following three ~~Constraints~~constraints in RUC:

(a) To ensure that sufficient RUC Capacity is procured to meet the CAISO Forecast of CAISO Demand, the CAISO will enforce the power balance between the total Supply, which includes Day-Ahead Schedules and RUC Capacity, and the total Demand, which includes the CAISO Forecast of CAISO Demand and IFM export Schedules. The CAISO may adjust the CAISO Forecast of CAISO Demand to increase the RUC procurement target if there is AS Bid insufficiency in the IFM.

(b) To ensure that RUC will neither commit an excessive amount of Minimum Load Energy nor procure an excessive amount of RUC Capacity from Scheduling Points the CAISO will verify that the sum of Day-Ahead Schedules, Schedules of ~~Generation~~Generating Units, net imports, Participating Loads, and Proxy Demand Resources plus the Minimum Load Energy committed by RUC is not greater than a configurable percentage of the system CAISO Forecast of CAISO Demand.

(c) The CAISO can limit the amount of RUC Capacity it will procure from resources that could otherwise be started during the Operating Day based on operational factors such as: (1) historical confidence that a Short Start Unit actually starts when needed based on the assessment of the CAISO Operators of the historical performance of Short Start Units; (2) need to conserve the number of run-hours and number of starts per year for critical loading periods; and (3) seasonal ~~Constraints~~constraints such as Overgeneration. The CAISO will verify that the total Day-Ahead Schedules and RUC Capacity from such resources is not greater than a configurable percentage of the total available capacity of all such resources.

31.5.5 Selection And Commitment Of RUC Capacity

Capacity that is not already scheduled in the IFM may be selected as RUC Capacity through the RUC process of the DAM. The RUC optimization will select RUC Capacity and produce nodal RUC Prices by minimizing total Bid cost based on RUC Availability Bids and Start-Up, Minimum Load Bids and Transition Costs. RUC will not consider Start-Up, Minimum Load Bids, or Transition Costs for resources already committed in the IFM. The RUC Capacity of a resource is the incremental amount of capacity selected in RUC above the resource's Day-Ahead Schedule. The resource's Day-Ahead Schedule plus its RUC Capacity comprise the resource's RUC Schedule. The CAISO will only issue RUC Start-Up Instructions to resources committed in RUC that must receive a Start-Up Instruction in the Day-Ahead in order to be available to meet Real-Time Demand. RUC Schedules will be provided to Scheduling Coordinators even if a RUC Start-Up Instruction is not issued at that time. RUC shall not Shut Down resources scheduled through the IFM and RUC will not commit a Multi-Stage Generating Resource to a lower MSG Configuration that is unable to support the Energy scheduled in the IFM. If the RUC process cannot find a feasible solution given the resources committed in the IFM, the RUC process will adjust ~~Constraints~~constraints as described in Section 31.5.4 to arrive at a feasible solution that accommodates all the resources committed in the IFM, and any necessary de-commitment of IFM committed units shall be effectuated through an Exceptional Dispatch.

31.6.4 [NOT USED]

~~By 6:00 a.m. on the day preceding the Trading Day, each Scheduling Coordinator shall provide to the CAISO a Demand Forecast specified by UDC Service Area for which it will submit a Bid for each of the Settlement Periods of the following Trading Day. The CAISO shall aggregate the Demand information by~~

~~UDC Service Area and transmit the aggregate Demand information to each UDC serving such aggregate Demand.~~

* * *

31.7 Extremely Long-Start Commitment Process

The CAISO shall perform the Extremely Long-Start Commitment Process (ELC Process) after the regular DAM results are posted. ELS Resources are flagged in the Master File and are the only resources eligible to be committed in the ELC Process. Each day after the DAM results are posted, the CAISO shall conduct the ELC Process to determine commitment of ELS Resources to be available to the CAISO Markets in the second day out. The CAISO will use the latest CAISO Forecast of CAISO Demand available to the CAISO for the Trading Day two days ahead of the current day that the ELC Process is executed. For commitment purposes for a resource whose ~~start-up time~~Start-Up Time would exceed the definition of an ELS Resource based on the ~~resources~~resource's initial condition and cooling time, the CAISO will consider DAM Bids from ELS Resources as Bids for the Trading Day two days ahead of the current day that the ELC Process is executed. The CAISO Operator shall use its operator judgment consistent with Good Utility Practice to determine whether ELS Resources for the second day in the 48-hour time period should be committed. The ELC Process does not dispatch Energy for the 48-hour time period and therefore the commitment instructions will not include megawatts schedules greater than the Minimum Load. ELS Resources receiving a commitment instruction are obligated to resubmit the same Bid in the next day's Day-Ahead Market. The CAISO Commitment Period or Self-Commitment Period determination for the ELS Resources depends on the DAM results and the Clean and Generated Bids, following the same rules that apply to other resources. All Commitment Intervals for the ELS Resources will be classified as CAISO Commitment Periods, unless there is a Self-Schedule or Self-Provided AS for that interval.

* * *

33.2 The HASP Optimization

After the Market Close for the HASP and RTM for the relevant Trading Hour, the Bids have been validated and the MPM-RRD process has been performed, the HASP optimization determines feasible but non-binding HASP Advisory Schedules for Generating Units for each fifteen-minute interval of the

Trading Hour, as well as binding hourly HASP Intertie Schedules and binding hourly HASP AS Awards from Non-Dynamic System Resources for that Trading Hour. The HASP may also commit resources whose Start-Up Times are within ~~its Time Horizon.~~the immediately following Trading Hour. The HASP, like the other runs of the RTUC, utilizes the same SCUC optimization {and Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6} as the IFM, with the {Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6} updated to reflect changes in system conditions as appropriate, to ensure that HASP Intertie Schedules are feasible. Instead of clearing against Demand Bids as in the IFM, the HASP clears Supply against the CAISO Forecast of CAISO Demand plus submitted Export Bids, to the extent the Export Bids are selected in the MPM-RRD process. The HASP optimization also factors in forecasted unscheduled flow at the Interties. The HASP optimization produces Settlement prices for hourly imports and exports to and from the CAISO Balancing Authority Area reflected in the HASP Intertie Schedule and for the HASP AS Awards for System Resources.

33.3 Treatment Of Self-Schedules In HASP

The HASP optimization clears Bids, including Self-Schedules, while preserving all priorities in this process consistent with Section 34.10. The HASP optimization does not adjust submitted Self-Schedules unless it is not possible to balance Supply and the CAISO Forecast of CAISO Demand plus Export Bids and manage Congestion using the available Economic Bids, in which case the HASP performs non-economic adjustments to Self-Schedules. The MWh quantities of Self-Schedules of Supply that clear in the HASP constitute a feasible Dispatch for the RTM at the time HASP is run, but the HASP results do not constitute a final Schedule for Generating Units because these resources may be adjusted non-economically in the RTD if necessary to manage Congestion and clear Supply and Demand. Self-Schedules submitted for ~~Generation~~Generating Units that clear in the HASP will be issued HASP Advisory Schedules. Scheduling Coordinators representing Participating Intermittent Resources whose output is being used to satisfy a resource adequacy requirement must submit Self-Schedules in HASP in accordance with the forecast provided by the independent forecast service provider. The submission of a change to an ETC Self-Schedule beyond the deadline specified in Section 16.9.1, that is permitted pursuant to the terms of the applicable ETC, shall not be deemed to be an unbalanced ETC Self-Schedule for the purposes of

Settlement, consistent with the ETC and TOR Self-Schedule Settlement treatment described in Section 11.5.7.

* * *

33.8.1 Eligibility To Set The HASP Intertie LMP

All Generating Units, Participating Loads, System Resources, System Units, or COGs subject to the provisions in Section 27.7 with Bids, including Generated Bids, that are unconstrained due to Ramp Rates or other temporal constraints are eligible to set the HASP Intertie LMP, provided that (a) the Generating Unit or Resource-Specific System Resource is Dispatched between its Minimum Operating Limit and the highest MW value in its Economic Bid or Generated Bid, or (b) the Participating Load, non-Resource-Specific System Resource, or System Unit is Dispatched between zero (0) MW and the highest MW value in its Economic Bid or Generated Bid. If (a) a resource's Dispatch is constrained by its Minimum Operating Limit or the highest MW value in its Economic Bid or Generated Bid, (b) the CAISO enforces a resource-specific constraint on the resource due to an RMR or Exceptional Dispatch, or (c) the resource's full Ramping capability is constraining its Dispatch for additional Energy in a target interval, the resource cannot be marginal and thus is not eligible to set the HASP Intertie LMP. Resources identified as MSS Load following resources are not eligible to set the HASP Intertie LMP. A Constrained Output Generator that has the ability to be committed or shut off within the ~~Time Horizon of~~immediately following Trading Hour in which a specific HASP run is conducted will be eligible to set the Dispatch Interval LMP if any portion of its Energy is necessary to serve Demand. Dispatches of Regulation resources to a Dispatch Operating Point by SCED will be eligible to set the HASP Intertie LMP.

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34. Real-Time Market

The RTM is the market conducted by the CAISO during any given Operating Day in which Scheduling Coordinators may provide Real-Time Imbalance Energy and Ancillary Services. The Real-Time Market consists of the Real-Time Unit Commitment (RTUC), the Short-Term Unit Commitment (STUC) and the Real-Time Dispatch (RTD) processes. The Short-Term Unit Commitment (STUC) runs once per hour near the top of the hour and utilizes the SCUC optimization to commit Medium Start, Short Start and Fast Start Units to meet the CAISO Demand Forecast. The CAISO shall dispatch all resources, including

Participating Load and Proxy Demand Resource, pursuant to submitted Bids or pursuant to the provisions below on Exceptional Dispatch. In Real-Time, resources are required to follow Real-Time Dispatch Instructions. ~~The Time Horizon of~~In any given Trading Hour, the STUC ~~starts with~~may commit resources for the third fifteen-minute interval of the current Trading Hour and extending ~~for~~into the next four Trading Hours. The RTUC runs every fifteen (15) minutes and utilizes the SCUC optimization to commit Fast Start and some Short Start ~~resources~~Units and to procure any needed AS on a fifteen-minute basis. ~~Any~~In any given ~~run of~~Trading Hour, the RTUC ~~will have a Time Horizon of approximately sixty (60) to 105 minutes (~~may commit resources in the four to seven subsequent fifteen-minute intervals~~)~~, depending on when during the hour the run occurs. Not all resources committed in a given STUC or RTUC run will necessarily receive CAISO commitment instructions immediately, because during the Trading Day the CAISO may issue a commitment instruction to a resource only at the latest possible time that allows the resource to be ready to provide Energy when it is expected to be needed. The RTD uses a Security Constrained Economic Dispatch (SCED) algorithm every five minutes throughout the Trading Hour to determine optimal Dispatch Instructions to balance Supply and Demand. Updates to the Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 used in the RTM optimization include current estimates of real-time unscheduled flow at the Interties. ~~The~~In any given five-minute interval, the RTD optimization ~~utilizes up to a sixty-five-minute Time Horizon (thirteen (13)~~looks ahead over multiple five-minute intervals~~),~~, but the CAISO issues Dispatch Instructions only for the next target five-minute Interval. The RTUC, STUC and RTD processes of the RTM use the same Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 used in the DAM and the HASP, subject to any necessary updates of the Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 pursuant to changes in grid conditions after the DAM has run. In the case of Multi-Stage Generating Resources, the RTM procedures will optimize Transition Costs in addition to the Start-Up and Minimum Load Costs. If a Scheduling Coordinator submits a Self-Schedule or a Submission to Self-Provide Ancillary Services for a given MSG Configuration in a given Trading Hour, all of the RTM processes will consider the Start-Up Cost, Minimum Load Cost, and Transition Cost associated with any Economic Bids for other MSG Configurations as incremental costs between the other MSG Configurations and the self-scheduled MSG

Configuration. In such cases, incremental costs are the additional costs incurred to transition or operate in an MSG Configuration in addition to the costs associated with the self-scheduled MSG Configuration.

* * *

34.2 Real-Time Unit Commitment

The Real-Time Unit Commitment (RTUC) process uses SCUC and is run every fifteen (15) minutes to: (1) make commitment decisions for Fast Start and Short Start ~~resources~~Units having Start-Up Times within the ~~Time Horizon of the RTUC process~~applicable time periods described below in this section, and (2) procure required additional Ancillary Services and calculate ASMP used for settling procured Ancillary Service capacity for the next fifteen-minute Real-Time Ancillary Service interval. In any fifteen (15) minute RTUC interval that falls within a time period in which a Multi-Stage Generating Resource is transitioning from one MSG Configuration to another MSG Configuration, the CAISO: (1) will not award any incremental Ancillary Services; (2) will disqualify any Day-Ahead Ancillary Services Awards; (3) will disqualify Day-Ahead qualified Submissions to Self-Provide Ancillary Services Award, and (4) will disqualify Submissions to Self-Provide Ancillary Services in RTM. For Multi-Stage Generating Resources the RTUC will issue a binding Transition Instruction separately from the binding Start-Up or Shut Down instructions. The RTUC can also be run with the Contingency Flag activated, in which case the RTUC can commit Contingency Only Operating Reserves. If RTUC is run without the Contingency Flag activated, it cannot commit Contingency Only Operating Reserves. RTUC is run ~~four times an hour,~~ at the following ~~times for the following Time Horizons~~time intervals: (1) at approximately 7.5 minutes prior to the next Trading Hour, in conjunction with the HASP run, for T-45 minutes to T+60 minutes; (2) at approximately 7.5 minutes into the current hour for T-30 minutes to T+60 minutes; (3) at approximately 22.5 minutes into the current hour for T-15 minutes to T+60 minutes; and (4) at approximately 37.5 minutes into the current hour for T to T+60 minutes where T is the beginning of the next Trade Hour. The HASP, described in Section 33, is a special RTUC run that is performed at approximately 7.5 minutes before each hour and has the additional responsibility of: (1) pre-dispatching Energy and awarding Ancillary Services for hourly dispatched System Resources for the Trading Hour that begins 67.5 minutes later, and (2) performing the necessary MPM-RRD for that Trading Hour. A Day-Ahead Schedule or RUC Schedule for an MSG Configuration that is later impacted by the resource's derate or outages, will be reconsidered in the RTUC process taking into consideration the impacts of the derate or outage on the available MSG Configurations.

34.2.1 Commitment Of Fast Start And Short Start Units

RTUC produces binding and advisory Start-Up and Shut-Down Dispatch Instructions for Fast Start and Short Start ~~resources~~Units that have Start-Up Times that would allow the resource to be committed prior to the end of the relevant ~~Time Horizon~~time period of the RTUC run as described in Section 34.2. A Start-Up Dispatch Instruction is considered binding in any given RTUC run if the Start-Up Time of the resource is such that there would not be sufficient time for a subsequent RTUC run to Start-Up the resource. A Start-Up Instruction is considered advisory if it is not binding, such that the resource could achieve its target Start-Up Time as determined in the current RTUC run in a subsequent RTUC run based on its Start-Up Time. A Shut-Down Instruction is considered binding if the resource could achieve the target Shut-Down Time as determined in the current RTUC in a subsequent RTUC run. A Shut-Down Dispatch Instruction is considered advisory if the resource Shut-Down Instruction is not binding such that the resource could achieve its target Shut-Down time as determined in the current RTUC run in a subsequent RTUC run. A binding Dispatch Instruction that results in a change in Commitment Status will be issued, in accordance with Section 6.3, after review and acceptance of the Start-Up Instruction by the CAISO Operator. An advisory Dispatch Instruction changing the Commitment Status of a resource may be modified by the CAISO Operator to a binding Dispatch Instruction and communicated in accordance with Section 6.3 after review and acceptance by the CAISO Operator. Only binding and not advisory Dispatch Instructions will be issued by the CAISO. For Multi-Stage Generating Resources the CAISO will also issue binding Transition Instructions when the Multi-Stage Generating Resource must change from one MSG Configuration to another. A Transition Instruction is considered binding in any given RTUC run if the Transition Time for the Multi-Stage Generating Resource is such that there would not be sufficient time for a subsequent RTUC run to transition the resource.

* * *

34.3.1 Real-Time Economic Dispatch

RTED mode of operation for RTD normally runs every five (5) minutes starting at approximately 7.5 minutes prior to the start of the next Dispatch Interval and produces ~~a~~ binding Dispatch

~~Instruction~~Instructions for Energy for the next Dispatch Interval and advisory Dispatch Instructions for ~~as many as twelve~~multiple future Dispatch Intervals ~~over~~through at least the ~~RTD optimization Time Horizon of sixty-five (65) minutes~~next Trading Hour. After being reviewed by the CAISO Operator, only binding Dispatch Instructions are communicated for the next Dispatch Interval in accordance with Section 6.3. RTED will produce a Dispatch Interval LMP for each PNode for the Dispatch Interval associated with the binding Dispatch Instructions. The RTED Dispatch target is the middle of the interval between five (5) minutes boundary points.

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34.3.3 Real-Time Manual Dispatch

RTMD mode of operation for RTD is a merit-order run activated upon CAISO Operator request as a backup process in case the normal RTED process fails to converge. The RTMD run will provide the CAISO Operator a list of resources and quantity of MW available for Dispatch in merit-order based on Operational Ramp Rate but otherwise ignores Transmission Losses and ~~network~~Transmission Constraints. The CAISO Operator may dispatch resources from the list by identifying the quantity of Imbalance Energy that is required for the system and/or directly selecting resources from the merit order taking into consideration actual operating conditions. After Dispatches have been selected, reviewed and accepted by the CAISO Operator, Dispatch Instructions will be communicated in accordance with Section 6.3. While the RTMD mode is being used for Dispatch a uniform five-minute MCP will be produced for all PNodes based on the merit order Dispatch. Until RTMD is actually run and RTMD-based Dispatch Instructions are issued after RTED fails to converge, all five-minute Dispatch Interval LMPs will be set to the last LMP at each Node produced by the last RTED run that converged.

* * *

34.4 Short-Term Unit Commitment

At the top of each Trading Hour, immediately after the RTUC run is completed, the CAISO performs an approximately five (5) hour Short-Term Unit Commitment (STUC) run using SCUC and the CAISO Forecast of CAISO Demand to commit Medium Start Units and Short Start Units with Start-Up Times greater than the ~~Time Horizon~~time period covered by the RTUC~~.~~ described in Section 34.2. The ~~Time Horizon for the~~ STUC ~~optimization run will extend~~looks ahead over a period of at least three hours beyond the Trading Hour for which the RTUC optimization was run, and will ~~replicate the~~utilize Bids ~~used in~~ available from other CAISO Markets for that Trading Hour for these additional hours. The CAISO revises these replicated Bids each time the hourly STUC is run, to utilize the most recently ~~submitted~~available Bids. A Start-Up Instruction produced by STUC is considered binding if the resource could not achieve the target Start-Up Time as determined in the current STUC run in a subsequent RTUC or STUC run as a result of the Start-Up Time of the resource. A Start-Up Instruction produced by STUC is considered advisory if it is not binding, such that the resource could achieve its target start time as determined in the current RTUC run

in a subsequent STUC or RTUC run based on its Start-Up Time. A binding Dispatch Instruction produced by STUC that results in a change in Commitment Status will be issued, in accordance with Section 6.3, after review and acceptance of the Start-Up Instruction by the CAISO Operator. The STUC will only decommit a resource to the extent that resource's physical characteristics allow it to be cycled in the same ~~Time Horizon~~approximately five (5) hour look-ahed time period for which it was ~~decommitted.~~previously committed. STUC does not produce ~~prices~~Locational Marginal Prices for Settlement. A Day-Ahead Schedule or RUC Schedule for an MSG Configuration that is later impacted by the resource's derate or outages, will be reconsidered in the STUC process taking into consideration the impacts of the derate or outage on the available MSG Configurations.

* * *

34.5 General Dispatch Principles

The CAISO shall conduct all Dispatch activities consistent with the following principles:

(1) The CAISO shall issue AGC instructions electronically as often as every four (4) seconds from its Energy Management System (EMS) to resources providing Regulation and on Automatic Generation Control to meet NERC and WECC performance requirements;

(2) In each run of the RTED or RTCD the objective will be to meet the projected Energy requirements over the ~~Time Horizon~~applicable forward-looking time period of that run, subject to transmission and resource operational ~~Constraints~~constraints, taking into account the short term CAISO Forecast of

CAISO Demand adjusted as necessary by the CAISO Operator to reflect scheduled changes to Interchange and non-dispatchable resources in subsequent Dispatch Intervals;

(3) Dispatch Instructions will be based on Energy Bids for those resources that are capable of intra-hour adjustments and will be determined through the use of SCED except when the CAISO must utilize the RTMD;

(4) When dispatching Energy from awarded Ancillary Service capacity the CAISO will not differentiate between Ancillary Services procured by the CAISO and Submissions to Self-Provide an Ancillary Service;

(5) The Dispatch Instructions of a resource for a subsequent Dispatch Interval shall take as a point of reference the actual output obtained from either the State Estimator solution or the last valid telemetry measurement and the resource's operational ramping capability. For Multi-Stage Generating Resources the determination of the point of reference is further affected by the MSG Configuration and the information contained in the Transition Matrix;

(6) In determining the Dispatch Instructions for a target Dispatch Interval while at the same time achieving the objective to minimize Dispatch costs to meet the forecasted conditions of the entire ~~Time Horizon~~forward-looking time period, the Dispatch for the target Dispatch Interval will be affected by: (a) Dispatch Instructions in prior intervals, (b) actual output of the resource, (c) forecasted conditions in subsequent intervals within the ~~Time Horizon~~forward-looking time period of the optimization, and (d) operational ~~Constraints~~constraints of the resource, such that a resource may be dispatched in a direction for the immediate target Dispatch Interval that is different than the direction of change in Energy needs from the current Dispatch Interval to the next immediate Dispatch Interval, considering the applicable MSG Configuration;

(7) Through Start-Up Instructions the CAISO may instruct resources to start up or shut down, or may reduce Load for Participating Loads and Proxy Demand

Resources, over the ~~Time Horizon~~forward-looking time period for the RTM based on submitted Bids, Start-Up Costs and Minimum Load Costs, Pumping Costs and Pump Shut-Down Costs, as appropriate for the resource, or for Multi-Stage Generating Resource as appropriate for the applicable MSG Configuration, consistent with operating characteristics of the resources that the SCED is able to enforce. In making Start-Up or Shut-Down decisions in the RTM, the CAISO may factor in limitations on number of run hours or Start-Ups of a resource to avoid exhausting its maximum number of run hours or Start-Ups during periods other than peak loading conditions;

(8) The CAISO shall only start up resources that can start within the ~~Time Horizon used by the RTM optimization methodology~~applicable time periods of the various CAISO Markets Processes that comprise the RTM;

(9) The RTM optimization may result in resources being shut down consistent with their Bids and operating characteristics provided that: (~~1~~a) the resource does not need to be on-line to provide Energy, (~~2~~b) the resource is able to start up within the applicable time periods of the processes that comprise the RTM ~~optimization Time Horizon, (3~~, (c) the Generating Unit is not providing Regulation or Spinning Reserve, and (~~4~~d) Generating Units online providing Non-Spinning Reserve may be shut down if they can be brought up within ten (10) minutes as such resources are needed to be online to provide Non-Spinning Reserves; (10) For resources that are both providing Regulation and have submitted Energy Bids for the RTM, Dispatch Instructions will be based on the Regulation Ramp Rate of the resource rather than the Operational Ramp Rate if the Dispatch Operating Point remains within the Regulating Range. The Regulating Range will limit the Ramping of Dispatch Instructions issued to resources that are providing Regulation;

(11) For Multi-Stage Generating Resources the CAISO will issue Dispatch Instructions by Resource ID and Configuration ID;

(12) The CAISO may issue Transition Instructions to instruct resources to transition from one MSG Configuration to another over the ~~Time Horizon~~forward-looking time period for the RTM based on submitted Bids, Transition Costs and Minimum Load Costs, as appropriate for the MSG Configurations involved in the MSG Transition, consistent with Transition Matrix and operating characteristics of these MSG Configurations. The RTM optimization will factor in limitations on Minimum Up Time and Minimum Down Time defined for each MSG configuration and Minimum Up Time and Minimum Down Time at the Generating Unit or Dynamic Resource-Specific System Resource.

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34.7 Utilization Of The Energy Bids

The CAISO uses Energy Bids for the following purposes: (i) satisfying Real-Time Energy needs; (ii) mitigating Congestion; (iii) maintaining aggregate Regulation reserve capability in Real-Time; (iv) allowing recovery of Operating Reserves utilized in Real-Time operations; (v) procuring Voltage Support required from resources beyond their power factor ranges in Real-Time; (vi) establishing LMPs; (vii) as the basis for Bid Cost Recovery; and (viii) to the extent a Real-Time Energy Bid Curve is submitted starting at minimum operating level for a Short Start ~~resource~~Unit that is scheduled to be on-line, the RTM may Dispatch such a resource down to its minimum operating level and may issue a Shut-Down Instruction to the resource based on its Minimum Load Energy costs.

* * *

34.9.1 System Reliability Exceptional Dispatches

The CAISO may issue a manual Exceptional Dispatch for ~~Generation~~Generating Units, System Units, Participating Loads, Proxy Demand Resources, Dynamic System Resources, and Condition 2 RMR Units pursuant to Section 41.9, in addition to or instead of resources with a Day-Ahead Schedule dispatched by RTM optimization software during a System Emergency, or to prevent an imminent System Emergency or a situation that threatens System Reliability and cannot be addressed by the RTM optimization and system modeling. To the extent possible, the CAISO shall utilize available and effective Bids from resources before dispatching resources without Bids. To deal with any threats to System Reliability, the

CAISO may also issue a manual Exceptional Dispatch in the Real-Time for Non-Dynamic System Resources that have not been or would not be selected by the RTM for Dispatch, but for which the relevant Scheduling Coordinator has submitted a Bid into the HASP.

34.9.2 Other Exceptional Dispatch

The CAISO may also issue manual Exceptional Dispatches for resources in addition to or instead of resources with a Day-Ahead Schedule or dispatched by the RTM optimization software to: (1) perform Ancillary Services testing; (2) perform pre-commercial operation testing for Generating Units; (3) perform periodic testing of Generating Units, including PMax testing; (4) mitigate for Overgeneration; (5) provide for Black Start; (6) provide for Voltage Support; (7) accommodate TOR or ETC Self-Schedule changes after the Market Close of the HASP; (8) reverse a commitment instruction issued through the IFM that is no longer optimal as determined through RUC; or (9) in the event of a Market Disruption, to prevent a Market Disruption, or to minimize the extent of a Market Disruption; or (10) reverse the operating mode of a Pumped-Storage Hydro Unit. The CAISO will not consider Start-Up Costs, Minimum Load Costs, or Energy Bids in connection with the issuance of Exceptional Dispatches to perform Ancillary Services testing, to perform PMax testing, or to perform pre-commercial operation testing for Generating Units.

* * *

34.15.1 Resource Constraints Version

The SCED shall enforce the following resource physical ~~Constraints~~constraints:

(a) Minimum and maximum operating resource limits. Outages and limitations due to transmission clearances shall be reflected in these limits. The more restrictive operating or regulating limit shall be used for resources providing Regulation so that the SCED shall not Dispatch them outside their Regulating Range.

(b) Forbidden Operating Regions. When ramping in the Forbidden Operating Region, the implicit ramp rate will be used as determined based on the time it takes for the resource to cross its Forbidden Operating Region. A resource can only be ramped through a Forbidden Operating Region after being dispatched into a Forbidden Operation Region. The CAISO will not Dispatch a resource within its Forbidden Operating Regions in the

Real-Time Market, except that the CAISO may Dispatch the resource through the Forbidden Operating Region in the direction that the resource entered the Forbidden Operating Region at the maximum applicable Ramp Rate over consecutive Dispatch Intervals. A resource with a Forbidden Operating Region cannot provide Ancillary Services in a particular fifteen (15) minute Dispatch Interval unless that resource can complete its transit through the relevant Forbidden Operating Region within that particular Dispatch Interval.

(c) Operational Ramp Rates and Start-Up Times. The submitted Operational Ramp Rate for resources shall be used as the basis for all Dispatch Instructions, provided that the Dispatch Operating Point for resources that are providing Regulation remains within their applicable Regulating Range. The Regulating Range will limit the Ramping of Dispatch Instructions issued to resources that are providing Regulation. The Ramp Rate for Non-Dynamic System Resources cleared in the HASP will not be observed. Rather, the ramp of the Non-Dynamic System Resource will respect inter-Balancing Authority Area Ramping conventions established by WECC. Ramp Rates for Dynamic System Resources will be observed like Participating Generators in the RTD. Each Energy Bid shall be Dispatched only up to the amount of Imbalance Energy that can be provided within the Dispatch Interval based on the applicable Operational Ramp Rate. The Dispatch Instruction shall consider the relevant Start-Up Time as, if the resource is off-line, the relevant Operational Ramp Rate function, and any other resource constraints or prior commitments such as Schedule changes across hours and previous Dispatch Instructions. The Start-Up Time shall be determined from the Start-Up Time function and when the resource was last shut down. The Start-Up Time shall not apply if the corresponding resource is on-line or expected to start.

(d) Maximum number of daily Start-Ups. The SCED shall not cause a resource to exceed its daily maximum number of Start-Ups.

(e) Minimum Run Time and Down Time. The SCED shall not start up off-line resources before their Minimum Down Time expires and shall not shut down on-line resources before their Minimum Run Time expires. For Multi-Stage Generating Resources these requirements shall be observed both for the Generating Unit or Dynamic Resource-Specific System Resource and MSG Configuration.

(f) Operating (Spinning and Non-Spinning) Reserve. The SCED shall Dispatch Spinning and Non-Spinning Reserve subject to the limitations set forth in Section 34.16.3.

(g) Non-Dynamic System Resources. If Dispatched, each Non-Dynamic System Resource flagged for hourly pre-dispatch in the next Trading Hour shall be Dispatched to operate at a constant level over the entire Trading Hour. The HASP shall perform the hourly pre-dispatch for each Trading Hour once prior to the Operating Hour. The hourly pre-dispatch shall not subsequently be revised by the SCED and the resulting HASP Intertie Schedules are financially binding and are settled pursuant to Section 11.4.

(h) Daily Energy use limitation to the extent that Energy limitation is expressed in a resource's Bid. If the Energy Limits are violated for purposes of Exceptional Dispatches for System Reliability, the Bid will be settled as provided in Section 11.5.6.1.

* * *

34.15.6 Intra-Hour Exceptional Dispatches

For the special case where an Exceptional Dispatch begins in the new hour and the rules above would result in the violation of the resource's inter-temporal constraint(s), the following rules are applied and the Energy is settled as Exceptional Dispatch Energy as described in Section 11.5.6.

(a) If the ramp time is greater than one hour or greater than what can be achieved when RTM receives the ~~Constraint~~constraint, RTM starts the ramp at the earliest possible time and continues Ramping the resource in the new Trading Hour.

(b) If the ramp time results in starting the ramp less than ten (10) minutes before the start of the hour, RTM instead starts the ramp at ten (10) minutes before the start of the hour and ramps the resource at a uniform rate so that it meets the ~~Constraint~~constraint by the start time of the Exceptional Dispatch.

(c) If the new hour's Day-Ahead Schedule is beyond the Exceptional Dispatch ~~Constraint~~constraint, RTM resumes the basic Ramping rules after the Exceptional Dispatch ~~Constraint~~constraint is met, but limits the Ramp Rate as necessary to ensure that the resource does not complete its ramp before ten (10) minutes after the hour.

* * *

34.16.3.4 Voltage Support

(a) Voltage Support provided from Generating Units shall meet the standards specified in this CAISO Tariff and ~~the~~ Part E of Appendix K~~;~~.

(b) ~~the~~The CAISO may Dispatch Generating Units to increase or decrease MVar output within ~~the~~ power factor limits of ~~0.9 lagging to 0.95 leading~~ established pursuant to Section 8.2.3.3 (or within other limits specified by the CAISO in any exemption granted pursuant to Section 8.2.3.3 ~~of the CAISO Tariff~~) at no cost to the CAISO when required for System Reliability~~;~~.

(c) The CAISO 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 the CAISO Tariff~~;~~.

(d) If Voltage Support is required in addition to that provided pursuant to Section 34.16.3.4 (b) and (c), the CAISO will reduce output of Participating Generators certified in accordance with Appendix K . The CAISO will select Participating Generators in the vicinity where such additional Voltage Support is required~~; and~~.

(e) ~~the~~The CAISO will monitor voltage levels at Interconnections to maintain them in accordance with the applicable inter-Balancing Authority Area agreements.

* * *

34.17.2 Dispatch Information To Be Supplied By SC

Each Scheduling Coordinator shall be responsible for the submission of Bids and Dispatch of Generation and Demand in accordance with its Day-Ahead Schedule. Each Scheduling Coordinator shall keep the CAISO apprised of any change or potential change in the current status of all Generating Units and Intertie Schedules. This will include any changes in Generating Unit capacity that could affect planned Dispatch and conditions that could affect the reliability of a Generating Unit. Each Scheduling Coordinator shall immediately pass to the CAISO any information which it receives from a Generator which the Generator provides to the Scheduling Coordinator pursuant to ~~Section 36~~Sections 34.11.1 and 34.11.2. Each Scheduling Coordinator shall immediately pass to the CAISO any information it receives from a MSS Operator which the MSS Operator provides to the Scheduling Coordinator regarding any change or potential change in the current status of all Generating Units, System Units and Intertie Schedules. This information includes any changes in MSS System Units and Generating Unit capacity that could affect planned Dispatch and conditions that could affect the reliability of the System Unit or Generating Unit.

* * *

34.19.2.3 Eligibility to Set the Real-Time LMP

All Generating Units, Participating Loads, Proxy Demand Resources, Dynamic System Resources, System Units, or COGs subject to the provisions in Section 27.7, with Bids, including Generated Bids, that are unconstrained due to Ramp Rates or other temporal constraints are eligible to set the LMP, provided that (a) a Generating Unit or a Dynamic Resource-Specific System Resource is Dispatched between its Minimum Operating Limit and the highest MW value in its Economic Bid or Generated Bid, or (b) a Participating Load, a Proxy Demand Resource, a Dynamic System Resource that is not a Resource-Specific System Resource, or a System Unit is Dispatched between zero (0) MW and the highest MW value within its submitted Economic Bid range or Generated Bid. If a resource is Dispatched below its Minimum Operating Limit or above the highest MW value in its Economic Bid range or Generated Bid, or the CAISO enforces a resource-specific constraint on the resource due to an RMR or Exceptional Dispatch, the resource will not be eligible to set the LMP. Resources identified as MSS Load following resources are not eligible to set the LMP. A resource constrained at an upper or lower operating limit or dispatched for a quantity of Energy such that its full Ramping capability is constraining the ability of the resource to be dispatched for additional Energy in target interval, cannot be marginal (i.e., it is constrained by the Ramping capability) and thus is not eligible to set the Dispatch Interval LMP. Non-Dynamic System Resources are not eligible to set the Dispatch Interval LMP. Dynamic System Resources are eligible to set the Dispatch Interval LMP. A Constrained Output Generator that has the ability to be committed or shut off within ~~the Time Horizon of~~applicable time periods that comprise the RTM will be eligible to set the Dispatch Interval LMP if any portion of its Energy is necessary to serve Demand. Dispatches of Regulation resources by EMS in response to AGC will not set the RTM LMP. Dispatches of Regulation resources to a Dispatch Operating Point by RTM SCED will be eligible to set the RTM LMP.

* * *

36.13.6 Clearing Of The CRR Auction

The SFT used to clear the CRR Auction will utilize the same DC FNM and optimization algorithm as the corresponding CRR Allocation, except that nominations to the CRR Auction will have associated price-quantity bid curves. The CRR Auction SFT will use the bid prices in determining which CRRs to award when not all nominations are simultaneously feasible, will select the set of simultaneously feasible CRRs with the highest total auction value as determined by the CRR bids, and will calculate nodal prices at each PNode of the DC FNM. In the event that there are two or more identical bids for a specific combination of CRR Source and CRR Sink that affect an overloaded constraint, the CRR Auction optimization cannot distinguish these bids based on either effectiveness or price and therefore the CRR Auction optimization will award each CRR bidder a pro rata share of the CRRs that can be awarded based on the bid MW amounts. Based on the nodal prices calculated by the CRR Auction SFT, the CRR Market Clearing Price per MW for a specific CRR will equal the nodal price at the CRR ~~Sink~~Source minus the nodal price at the CRR ~~Source.~~ Sink.

* * *

36.15 [NOT USED]

~~The CAISO shall reduce the terms of any Firm Transmission Right that were released under Section 36 of the CAISO Tariff in effect prior to March 31, 2009, for any hours beginning at hour beginning 12:00 a.m.~~

~~on April 1, 2009 and ends with the hour beginning at 11:00 p.m., on March 31, 2010 for any month that the CAISO is operating with Congestion Revenue Rights as provided in Section 36 of the CAISO Tariff in effect after March 31, 2009. The CAISO shall also refund to the FTR Holders the FTR auction Settlement amounts associated with the reduced terms of the FTRs proportionately. The CAISO shall reflect any resulting payments in a subsequent invoice per the ISO Payments Calendar as soon as practicable. The amount of interest to be paid to each party that was awarded FTRs in the FTR auction that are reduced in term shall be determined so that for each month for which the FTR auction is resettled the CAISO will realize neither a shortfall nor a surplus of funds and all affected FTR Holders will receive the same effective interest rate for the month. Thus the effective interest rate paid to the affected FTR Holders shall be based on the interest rate the CAISO has earned on amounts held in the monthly FTR auction accounts.~~

* * *

37.2.1.1 Expected Conduct

Market Participants must comply with operating orders issued by the CAISO as authorized under the CAISO Tariff. For purposes of enforcement under this Section 37.2, an operating order shall be an order(s) from the CAISO directing a Market Participant to undertake, a single, clearly specified action (e.g., the operation of a specific device, or change in status of a particular Generating Unit) that is feasible and intended to resolve a specific operating condition. Deviation from an ADS Dispatch Instruction shall not constitute a violation of this Section 37.2.1.1. A Market Participant's failure to obey an operating order containing multiple instructions to address a specific operating condition will result in a single violation of Section 37.2. If some limitation prevents the Market Participant from fulfilling the action requested by the CAISO or the action is otherwise infeasible, then the Market Participant must promptly and directly communicate the nature of any such limitation or infeasibility to the CAISO.

* * *

37.2.5 Enhancements And Exceptions

Except as otherwise specifically provided, penalty amounts shall be tripled for any violation of Section 37.2.1, Section 37.2.2 or Section 37.2.4 if a CAISO System Emergency exists at the time an operating order becomes effective or at any time during the Market Participant's non-performance. Notwithstanding the foregoing, violations of Section 37.2.1, Section 37.2.2 and Section 37.2.4 are subject to penalty under this ~~rule~~Section 37.2 only to the extent that the CAISO has issued a separate and distinct non-automated Dispatch Instruction to the Market Participant. Any penalty amount that is tripled under this provision and that would exceed the $10,000 per day penalty limit shall not be levied against a Market Participant until the CAISO proposes and the Commission approves such an enhancement. A Market Participant that is subject to an enhanced penalty amount under this Section 37.2.5 may appeal that penalty amount to FERC if the Market Participant believes a mitigating circumstance not covered in Section 37.9.2 exists. The duty of the Market Participant to pay the enhanced penalty amount will be tolled until FERC renders its decision on the appeal.

* * *

37.4.1.1 Expected Conduct

A Market Participant shall notify the CAISO Control Center of any Outage reportable pursuant to Section 9.3.10.~~2~~3.1 of a Generating Unit subject to Section 4.6 within sixty (60) minutes after the Outage is discovered.

* * *

37.4.3.1 Expected Conduct

As required by Section 9.3.10.6, a Market Participant must provide a detailed explanation of a Forced Outage within two (2) Business Days after the Operator initially notifies the CAISO pursuant to Section 9.3.10.~~2~~3.1 of the change in maximum output capability. An Operator must promptly provide information requested by the CAISO to enable the CAISO to review the explanation submitted by the Operator and to prepare a report on the Forced Outage.

* * *

37.5.2.1 Expected Conduct

Market Participants shall provide complete and accurate Settlement Quality Meter Data for each Trading Hour and shall correct any errors in such data ~~prior to the issuance of Initial Settlement Statement T+7B or Recalculation Settlement Statement, as relevant. Failure~~no later than forty-three (43) calendar days after the Trading Day (T+43C). The failure to provide complete and accurate Settlement Quality Meter

Data, as required by Section 10 ~~and~~ that ~~results in~~causes an error ~~that is discovered after issuance of an Initial Settlement Statement~~ to exist in such Settlement Quality Meter Data after forty-three (43) calendar days after the Trading Day (T+~~7B or Recalculation Settlement Statement, as relevant,~~43C) shall be a violation of this rule. Scheduling Coordinators that fail to submit Scheduling Coordinator Estimated Settlement Quality Meter Data that is complete and based on a good faith estimate that reasonably represents Demand and/or Generation quantities for each Settlement Period as required by Section 10 and that results in an error that is discovered after ~~issuance of an Initial Settlement Statement T+7B or Recalculation Settlement Statement, as relevant,~~forty three (43) calendar days after the Trading Day (T+43C) shall be a violation of this rule.

* * *

37.8.10 Review Of Determination

A Market Participant that receives a Sanction may obtain immediate review of the CAISO's determination by directly appealing to FERC, in accordance with FERC's rules and procedures. In such case, the applicable Scheduling Coordinator shall also dispute the Initial Settlement Statement T~~+ 38 BD~~+7B containing the financial penalty, in accordance with Section 11. The Initial Settlement Statement T~~+ 38 BD~~+7B dispute and appeal to FERC must be made in accordance with the timeline for raising disputes specified in Section 11.29.8.~~2.~~ The penalty will be tolled until FERC renders its decision on the appeal. The disposition by FERC of such appeal shall be final, and no separate dispute of such Sanction may be initiated under Section 13, except as provided in Section 37.9.3.4. For the purpose of applying the time limitations set forth in Section 37.10.1, a ~~sanction~~Sanction will be considered assessed when it is included on an Initial Settlement Statement T~~+ 38 BD~~+7B, whether or not the CAISO accepts a Scheduling Coordinator's dispute of such Initial Settlement Statement T~~+ 38 BD~~+7B pending resolution of an appeal to FERC in accordance with this section or Section 37.9.3.3.

* * *

37.9.3.1 Settlement Statements

The CAISO will administer any penalties issued under this Section 37 through Initial Settlement Statements T~~+ 38 BD, and Initial Settlement Statement Reissues~~+7B or Recalculation Settlement Statements, as relevant, issued to the responsible Scheduling Coordinator by the CAISO. Before invoicing a financial penalty through the Settlement process, the CAISO will provide a description of the penalty to the responsible Scheduling Coordinator and all Market Participants the Scheduling Coordinator represents that are liable for the penalty, when the CAISO has sufficient objective information to identify and verify responsibility of such Market Participants. The CAISO shall specify whether such penalty is modified pursuant to Section 37.2.5 or Section 37.4.4. The description shall include the identity of the Market Participant that committed the violation and the amount of the penalty. Where FERC has determined the Sanction, the CAISO will provide such of the above information as is provided to it by FERC. The CAISO also may publish this information under the CAISO Website after ~~Initial Settlement Statement Reissues or~~ Recalculation Settlement Statements~~, as relevant,~~ are issued.

* * *

37.11.1 Method For Calculating Inaccurate Meter Data Penalty

There is no Sanction for the submission of inaccurate Meter Data used for an Initial Settlement Statement T+ 7B. However, an error in submitted Meter Data that ~~is discovered after issuance of a Recalculation Settlement Statement~~exists after forty three (43) calendar days after the Trading Day (T+43C) constitutes a Rule of Conduct violation. The level of the Sanction depends on whether the Scheduling Coordinator or the CAISO discovered the error. An increased penalty will apply for errors that are discovered by the CAISO.

Table A1 below shows how the level of the Sanction depends on the following factors: whether or not the Scheduling Coordinator finds the error; whether or not the Scheduling Coordinator owes the market, and whether or not the CAISO performs a re-run of the market or produces a Recalculation Settlement Statement. If the CAISO issues a Recalculation Settlement Statement or performs a re-run, then Settlement to all Scheduling Coordinators is recalculated, and the impact of such re-runs on charges assessed will be considered. A penalty charge equal to thirty (30) percent ~~(30%)~~ of the estimated value of the Energy error will apply if the Scheduling Coordinator discovers the error or seventy-five (75) percent ~~(75%)~~ of the estimated value of the Energy error if the CAISO discovers the error. Penalty assessment and disposition of penalty proceeds will be administered as described in Section 37.9.1 and Section 37.9.4 respectively. A Sanction will not be imposed unless such Sanction is more than $1,000 for at least one Trading Day during the period for which there was incomplete or inaccurate Meter Data.

Table A1 – Calculation of Inaccurate Meter Data Penalty When There Is A Recalculation Settlement Statement or re-run Case	Does SC Owe Market?	
Case 1: SC Identifies Inaccurate Meter Data	Yes	Penalty = (MWh x applicable price) x 0.30
Case 1: SC Identifies Inaccurate Meter Data	No	Penalty = (MWh x applicable price) x 0.30
Case 2: CAISO Identifies Inaccurate Meter Data	Yes	Penalty = (MWh x applicable price) x 0.75
Case 2: CAISO Identifies Inaccurate Meter Data	No	Penalty = (MWh x applicable price) x 0.75

Note to Table A1:

The applicable price will be the greater of: (1) the simple average of the relevant ~~hourly LMP~~twelve (12) five-minute LMPs for each hour in which inaccurate meter data occurred; or (2) $10/MWh. The LMP used will be the values posted on OASIS for each Trading Hour of the applicable Trading Day period.

2. Method for Calculating Inaccurate Meter Data Penalty When there is not a Recalculation Settlement Statement or re-run.

If the CAISO does not perform a Recalculation Settlement Statement or re-run, for cases of inaccurate Meter Data, Table A2 will be used to determine and allocate penalty and any market adjustment amount.

The market adjustment approximates the financial impact on the market; however, it does not completely reflect all the Settlement consequences of inaccurately submitted Meter Data. The approximated value of the inaccurate Meter Data in question will be calculated and returned to the market based on the average of the pro rata share of Unaccounted for Energy (UFE) charged in the utility Service Area during the period of the inaccurate Meter Data event. The thirty (30) percent ~~(30%)~~ or seventy-five (75) percent ~~(75%)~~ penalty will be distributed as discussed in Section 37.9.4. For cases where the CAISO does not perform a Recalculation Settlement Statement or re-run and the Scheduling Coordinator does not owe the market, then no market adjustment will be performed and no penalty will be assessed.

TABLE A2- Calculation Of Inaccurate Meter Data Penalty When There Is Not a Recalculation Settlement Statement or re-run Case	Does SC Owe Market?	CAISO does not perform a Recalculation Settlement Statement or re-run
Case 1: SC Identifies Inaccurate Meter Data	Yes	Market Adjustment = (MWh x applicable price) Penalty = (MWh x applicable price)) x 0.30
Case 1: SC Identifies Inaccurate Meter Data	No	No market adjustment will be made ~~Penalty = (MWh x Hourly LMP) x 0.30~~
Case 2: CAISO Identifies Inaccurate Meter Data	Yes	Market Adjustment = (MWh x applicable price) Penalty = (MWh x applicable price) x 0.75
Case 2: CAISO Identifies Inaccurate Meter Data	No	No market adjustment will be made ~~Penalty = (MWh x Hourly LMP) x 0.75~~

Notes to Table A2:

The applicable price will be the greater of: (1) the simple average of the relevant ~~hourly LMP~~twelve (12) five-minute LMPs for each hour in which inaccurate meter data occurred; or (2) $10/MWh. The LMP used will be the value posted on OASIS for each Trading Hour of the applicable Trading Day.

A Sanction will be imposed only if the Sanction is more than $1,000 for at least one Trading Day during the period for which there was incomplete or inaccurate Meter Data.

If the error is to the detriment of the responsible Scheduling Coordinator (e.g., under-reported Generation or over-reported Demand), and the CAISO does not produce a Recalculation Settlement Statement or perform a re-run, then no market adjustment will be made~~.~~ and no penalty will be assessed. If the CAISO produces a Recalculation Settlement Statement or performs a re-run after the error is corrected, then the Scheduling Coordinator will be given credit for the additional Energy through the normal Settlement process. If the Scheduling Coordinator is paid for an error due to a Recalculation Settlement Statement or re-run, then a Sanction will be assessed to assure that Recalculation Settlement Statements or re-runs do not diminish the incentive to correct such errors. This Sanction would be thirty ~~percent~~ (30~~%~~)) percent of the Energy value of the error if the Scheduling Coordinator discovers the error or seventy-five (75) percent ~~(75%)~~ estimated value of the error if the CAISO discovers the error.

If the error is to the detriment of the market, then a charge equal to thirty (30) percent ~~(30%)~~ or seventy-five (75~~%~~)) percent of the estimated value of the error, as appropriate, will be added to the charge for the Energy. If there is no Recalculation Settlement Statement or re-run, then the cost of Energy supplied by the CAISO (and inappropriately charged to the market as Unaccounted for Energy) must be recovered as well, and the charge will be equal to ~~130% or 175%~~one-hundred thirty (130) percent or one-hundred seventy five (175) percent of the estimated value of the error, as appropriate.

* * *

39.3.1 Conduct Regarding Bidding, Scheduling Or Facility Operation

Mitigation Measures may be applied to bidding, scheduling or operation of an Electric Facility or as specified in Section 39.3.1. 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 CAISO

Markets if exercised from a position of market power. Accordingly, the CAISO shall monitor the CAISO 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 a CAISO 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 for an Electric Facility when it would be in the economic interest, absent market power, of the withholding entity to do so, (iii) declining Bids called upon by the CAISO (unless the CAISO 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 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 LMPs.

(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~~Transmission Constraint.

(4) Bidding practices that distort prices or uplift charges away from those expected in a competitive market, such as registering Start-Up Cost and Minimum Load Cost data or submitting Bid Costs on behalf of an Electric Facility that are unjustifiably high (relative to known operational characteristics and/or the known operating cost of the resource) or misrepresenting the physical operating capabilities of an

Electric Facility resulting in uplift payments or prices significantly in excess of actual costs.

* * *

39.6.1.6.1 Gas Price Component of Projected Proxy Cost

For natural gas fired resources, the CAISO will calculate a gas price to be used in establishing maximum Start-Up Costs and Minimum Load Costs after the twenty-first day of each month and post it on the CAISO Website by the end of each calendar month. The price will be applicable for Scheduling Coordinators electing the Registered Cost option until a new gas price is calculated and posted on the CAISO Website. The gas price will be calculated as follows:

(1) Daily closing prices for monthly ~~NYMEX Natural Gas Futures~~natural gas futures contracts at Henry Hub for the next calendar month are averaged over the first twenty-one (21) days of the month, resulting in a single average for the next calendar month.

(2) Daily prices for ~~NYMEX~~ futures contracts for basis swaps at identified California delivery points, are averaged over the first twenty-one (21) days of the month for the identified California delivery points as set forth in the Business Practice Manual.

(3) For each of the California delivery point, the average Henry Hub and basis swap prices are combined and will be used as the baseline gas price applicable for calculating the caps for Start-Up and Minimum Load costs for resources electing the Registered Cost option. The most geographically appropriate will apply to a particular resource.

(4) The applicable intra-state gas transportation charge as set ~~froth~~forth in the Business Practice Manual will be added to the baseline gas price for each resource that elects the Registered Cost option to create a final gas price for calculating the caps for Start-Up and Minimum Load Costs for each such resource.}

For non-gas fired resources, the Projected Proxy Costs for Start-Up Costs and Minimum Load Costs will be calculated using the information contained in the Master File used for calculating the Proxy Cost, as set forth in the Business Practice Manual.

* * *

39.7 Local Market Power Mitigation For Energy Bids

Local ~~market power mitigation~~Market Power Mitigation is based on a periodic assessment and designation of ~~transmission constraints~~Transmission Constraints as competitive or non-competitive. Such periodic assessment will be performed at a minimum on an annual basis and potentially more frequently if needed due to changes in system conditions, network topology, or market performance. Any changes in ~~constraint~~Transmission Constraints designations will be publicly noticed prior to making the change. Upon determination that an ad hoc assessment is warranted, the CAISO will notice ~~market participants~~Market Participants that such an assessment will be performed. The determination whether a unit is being dispatched to relieve ~~congestion~~Congestion on a competitive or non-competitive ~~transmission constraint~~Transmission Constraint is based on two preliminary market runs that are performed prior to the actual pricing run of the market and are described in Sections 31 and 33 for the DAM and RTM, respectively.

39.7.1 Calculation Of Default Energy Bids Version

Default Energy Bids shall be calculated by the CAISO, for the on-peak hours and off-peak hours for both the DAM and RTMs, pursuant to one of the methodologies described in this Section. The Scheduling Coordinator for each Generating Unit owner or Participating Load must rank order the following options of calculating the Default Energy Bid starting with its preferred method. The Scheduling Coordinator must provide the data necessary for determining the Variable Costs unless the Negotiated Rate Option precedes the Variable Cost ~~option~~Option in the rank order, in which case the Scheduling Coordinator must have a negotiated rate established with the Independent Entity charged with calculating the Default Energy Bid. If no rank order is specified for a Generating Unit or Participating Load, then the default rank order of (1) Variable Cost Option, (2) Negotiated Rate Option, (3) LMP Option will be applied. For the first ninety (90) days after changes to resource status and MSG Configurations as specified in Section 27.8.3, including the first ninety (90) days after the effective date of Section 27.8.3, the Default Energy Bid option for the resource is limited to the Negotiated Rate Option or the Variable Cost Option.

* * *

39.7.1.1.1 Incremental Fuel Cost Calculation Under the Variable Cost Option

For natural gas-fueled units, incremental fuel cost is calculated based on an incremental heat rate curve multiplied by the natural gas price calculated as described below.

Resource owners shall submit to the CAISO average heat rates (Btu/kWh) measured for at least two (2) and up to eleven (11) generating operating points (MW), where the first and last operating points refer to the minimum and maximum operating levels (i.e., PMin and PMax), respectively. The average heat rate curve formed by the (Btu/kWh, MW) pairs is a piece-wise linear curve between operating points, and two (2) average heat rate pairs yield one (1) incremental heat rate segment that spans two (2) consecutive operating points. The incremental heat rates (Btu/kWh) in the incremental heat rate curve are calculated by converting the average heat rates submitted by resource owners to the CAISO to requirements of heat input (Btu/h) for each of the operating points and dividing the changes in requirements of heat input from one (1) operating point to the next by the changes in MW between two (2) consecutive operating points as specified in the Business Practice Manual. For each segment representing operating levels below eighty (80) percent ~~(80%)~~ of the unit's PMax, the incremental heat rate is limited to the maximum of the average heat rates for the two (2) operating points used to calculate the incremental heat rate segment.

The unit's final incremental fuel cost curve is calculated by multiplying this incremental heat rate curve by the applicable natural gas price, and then, if necessary, applying a left-to-right adjustment to ensure that the final incremental cost curve is monotonically non-decreasing.

For non-natural gas-fueled units, incremental fuel cost is calculated based on an average cost curve as described below.

Resource owners for non-natural gas-fueled units shall submit to the CAISO average fuel costs ($/MW) measured for at least two (2) and up to eleven (11) generating operating points (MW), where the first and last operating points refer to the minimum and maximum operating levels (i.e., PMin and PMax), respectively. The average cost curve formed by the ($/MWh, MW) pairs is a piece-wise linear curve between operating points, and two (2) average cost pairs yield one (1) incremental cost segment that spans two (2) consecutive operating points. For each segment representing operating levels below eighty (80) percent ~~(80%)~~ of the unit's PMax, the incremental cost rate is limited to the maximum of the average cost rates for the two (2) operating points used to calculate the incremental cost segment. The unit's final incremental fuel cost curve is then adjusted, if necessary, applying a left-to-right adjustment to ensure that the final incremental cost curve is monotonically non-decreasing.

Heat rate curves and average cost curves shall be stored, updated, and validated in the Master File. To calculate the natural gas price, the CAISO will use different gas price indices for the Day-Ahead Market and the Real-Time Market and each gas price index will be calculated using at least two prices from two or more of the following publications: Natural Gas Intelligence, ~~Btu~~SNL Energy/BTU's Daily Gas Wire, Platt's Gas Daily and the Intercontinental Exchange. If a gas price index is unavailable for any reason, the CAISO will use the most recent available gas price index. For the Day-Ahead Market, the CAISO will update the gas price index between ~~00~~19:00 and ~~03~~22:00 Pacific Time ~~in the Day-Ahead~~ using natural gas prices published ~~on the~~two days prior ~~day~~to the applicable Trading Day, unless gas prices are not published on that day, in which case the CAISO will use the most recently published prices that are available. For the Real-Time Market, the CAISO will update gas price indices between the hours of 19:00 and 22:00 Pacific Time using natural gas prices published ~~in~~one day prior to the applicable Trading Day~~-Ahead~~, unless gas prices are not published on that day, in which case the CAISO will use the most recently published prices that are available.

39.7.1.2 LMP Option

The CAISO will calculate the LMP Option for the Default Energy Bid as a weighted average of the lowest quartile of LMPs at the Generating Unit PNode in periods when the unit was Dispatched during the preceding ninety (90) ~~days.~~day period for which LMPs that have passed the price validation and correction process set forth in Section 35 are available. The weighted average will be calculated based on the quantities Dispatched within each segment of the Default Energy Bid curve.~~ The LMP Option for Default Energy Bids will not be available until ninety (90) days of LMP pricing has occurred.~~ Each Bid segment created under the LMP Option for Default Energy Bids will be subject to a feasibility test, as set forth in a Business Practice Manual, to determine whether there are a sufficient number of data points to allow for the calculation of an LMP based Default Energy Bid. The feasibility test is designed to avoid excessive volatility of the Default Energy Bid under the LMP Option that could result when calculated based on a relatively small number of prices.

* * *

39.7.2.1 Timing of Assessments

The CAISO will complete the first assessment of competitiveness of ~~transmission constraints~~Transmission Constraints prior to the effective date of this provision. Constraint designations resulting from the first assessment will be applied in the MPM-RRD mechanism on the day this CAISO Tariff becomes effective and will not be changed until a subsequent assessment has been performed. The CAISO may perform additional competitive constraint assessments during the year if changes in transmission infrastructure, generation resources, or Load, in the CAISO Balancing Authority Area and adjacent Balancing Authority Areas suggest material changes in market conditions or if market outcomes are observed that are inconsistent with competitive market outcomes. The CAISO will calculate and post path designations not less than once prior to the effective date of this tariff provision and not less than four (4) times each year thereafter to provide timely seasonal path designations.

39.7.2.2 Criteria

~~A transmission constraint~~A Transmission Constraint will be deemed competitive if no three unaffiliated suppliers are jointly pivotal in relieving congestion on that constraint. The determination of whether or not the pivotal supplier criteria for an individual constraint are violated will be assessed using the Feasibility Index described in Section 39.7.2.4. Assessment of competitiveness will be performed assuming various system conditions potentially including but not limited to season, load, planned transmission and resource outages. If an individual constraint fails the pivotal supplier criteria under any of these system conditions, the constraint will be deemed uncompetitive for the entire year under all system conditions until a subsequent assessment deems the constraint competitive. In general, a constraint may be an individual transmission line or a collection of lines that create a distinct ~~transmission constraint.~~Transmission Constraint. For purposes of the competitive assessment, the set of constraints that will be included in the network model are those modeled along with transmission limits expected to be enforced in clearing the CAISO Markets.

* * *

39.10 Mitigation Of Exceptional Dispatches Of Resources

During the period commencing on the effective date of this section and ending at midnight on the last day of the fourth calendar month following such effective date, the CAISO shall apply Mitigation Measures to all Exceptional Dispatches eligible for an Exceptional Dispatch ICPM designation under Section 43.1.5. During the period commencing on the first day of the fifth calendar month following the effective date of this section and ending at midnight on the last day of the twenty-fourth calendar month following such effective date, the CAISO shall apply Mitigation Measures to Exceptional Dispatches of resources when such resources are committed or dispatched under Exceptional Dispatch for purposes of: (1) addressing reliability requirements related to non-competitive ~~transmission~~Transmission Constraints; and (2) addressing unit-specific environmental ~~Constraints~~constraints not incorporated into the Full Network Model or the CAISO's market software that affect the dispatch of Generating Units in the Sacramento Delta and are commonly known as "Delta Dispatch". After the last day of the twenty-fourth calendar month following the effective date of this section, this entire Section 39.10 and the entirety of related Section 11.5.6.7, Section 43.1.5, and Section 43.2.6 shall no longer apply.

* * *

40.3.1.2 Local Capacity Technical Study Contingencies.

The Local Capacity Technical Study shall assess the following Contingencies: **Contingency Component(s)**
NERC/WECC Performance Level A – No Contingencies
<u>NERC/WECC Performance Level B – Loss of a single element</u> 1. Generator (G-1) 2. Transmission Circuit (L-1) 3. Transformer (T-1) 4. Single Pole (dc) Line 5. G-1 system readjusted L-1
<u>NERC/WECC Performance Level C – Loss of two or more elements</u> 3. L-1 system readjusted G-1 3. G-1 system readjusted T-1 or T-1 system readjusted G-1

3. L-1 system readjusted T-1 or T-1 system readjusted L-1 3. G-1 system readjusted G-1 3. L-1 system readjusted L-1 4. Bipolar (dc) Line 5. Two circuits (Common Mode) L-2 ~~9. SLG fault (stuck breaker or protection failure) for Bus section~~ WECC-S3. Two generators (Common Mode) G-2
D – Extreme event – loss of two or more elements Any B1-4 system readjusted (Common Mode) L-2 ~~All other extreme combinations D1-14.~~

* * *

40.5.1 Day Ahead Scheduling And Bidding Requirements

(1) Scheduling Coordinators on behalf of Modified Reserve Sharing LSEs serving Load within the CAISO Balancing Authority Area for whom they submit Demand Bids shall submit into the IFM Bids or Self-Schedules for Demand equal to one hundred (100) percent ~~(100%)~~ and for Supply equal to one hundred and fifteen (115) percent ~~(115%)~~ of the hourly Demand Forecasts for each Modified Reserve Sharing LSE it represents for each Trading Hour for the next Trading Day. Subject to Section 40.5.5, the resources included in a Self-Schedule or a Bid in each Trading Hour to satisfy one hundred and fifteen percent (115%) of the Modified Reserve Sharing LSE's hourly Demand Forecasts will be deemed Resource Adequacy Resources and (a) shall be comprised of those resources listed in the Modified Reserve Sharing LSE's monthly Resource Adequacy Plan and (b) shall include all Local Capacity Area Resources listed in the Modified Reserve Sharing LSE's annual Resource Adequacy Plan, if any, except to the extent the Local Capacity Area Resources, if any, are unavailable due to any

Outages or reductions in capacity reported to the CAISO in accordance with this CAISO Tariff.

(i) Local Capacity Area Resources physically capable of operating must submit: (a) Economic Bids for Energy and/or Self-Schedules for all their Resource Adequacy Capacity and (b) Economic Bids for Ancillary Services and/or a Submission to Self-Provide Ancillary Services for all of their Resource Adequacy Capacity that is certified to provide Ancillary Services. For Local Resource Adequacy Capacity that is certified to provide Ancillary Services and is not covered by a Submission to Self-Provide Ancillary Services, the resource must submit Economic Bids for each Ancillary Service for which the resource is certified. For Resource Adequacy Capacity subject to this requirement for which no Economic Energy Bid or Self-Schedule has been submitted, the CAISO shall insert a Generated Bid in accordance with Section 40.6.8. For Resource Adequacy Capacity subject to this requirement for which no Economic Bids for Ancillary Services or Submissions to Self-Provide Ancillary Services have been submitted, the CAISO shall insert a Generated Bid in accordance with Section 40.6.8 for each Ancillary Service the resource is certified to provide. However, to the extent the Generating Unit providing Local Capacity Area Resource capacity constitutes a Use-Limited Resource under Section 40.6.4, the provisions of Section 40.6.4 will apply.

(ii) Resource Adequacy Resource must participate in the RUC to the extent that the resource has available Resource Adequacy Capacity that was offered into the IFM and is not reflected in an IFM Schedule. Resource Adequacy Capacity participating in RUC will be optimized using zero dollar ($0/MW-hour) RUC Availability Bid.

(iii) Capacity from Resource Adequacy Resources selected in RUC will not be eligible to receive a RUC Availability Payment.

(iv) Through the IFM co-optimization process, the CAISO will utilize available Local Capacity Area Resource Adequacy Capacity to provide Energy or Ancillary Services in the most efficient manner to clear the Energy market, manage congestion and procure required Ancillary Services. In so doing the IFM will honor submitted Energy Self-Schedules of the Local Capacity Area Resource Adequacy Capacity of the Modified Reserve Sharing LSE unless the CAISO is unable to satisfy one hundred (100) percent ~~(100%)~~ of the Ancillary Services requirements. In such cases the CAISO may curtail all or a portion of a submitted Energy Self-Schedule to allow Ancillary Service-certified Local Capacity Area Resource Adequacy Capacity to be used to meet the Ancillary Service requirements. The CAISO will not curtail for the purpose of meeting Ancillary Service requirements a Self-Schedule of a resource internal to a Metered Subsystem that was submitted by the Scheduling Coordinator for that Metered Subsystem. If the IFM reduces the Energy Self-Schedule of Resource Adequacy Capacity to provide an Ancillary Service, the Ancillary Service Marginal Price for that Ancillary Service will be calculated in accordance with Section 27.1.2 using the Ancillary Service Bids submitted by the Scheduling Coordinator for the Resource Adequacy Resource or inserted by the CAISO pursuant to this Section 40.5.1, and using the resource's Generated Energy Bid to determine the Resource Adequacy Resource's opportunity cost of Energy. If the Scheduling Coordinator for the Modified Reserve Sharing LSE's Resource Adequacy Resource believes that the opportunity cost of Energy based on the Resource Adequacy Resource's Generated Energy Bid is insufficient to compensate for the resource's actual opportunity cost, the Scheduling Coordinator may submit evidence justifying the increased amount to the CAISO and to the FERC no later than seven (7) days after the end of the month in which the submitted Energy Self-Schedule was reduced by the CAISO to provide an Ancillary Service. The CAISO will treat such information as confidential and will apply the procedures in Section 20.4 of this CAISO Tariff with regard to requests for disclosure of such information. The CAISO shall pay the higher opportunity costs after those amounts have been approved by FERC.

(2) Resource Adequacy Resources of Modified Reserve Sharing LSEs that do not clear in the IFM or are not committed in RUC shall have no further offer requirements in HASP or Real-Time, except under System Emergencies as provided in this CAISO Tariff.

(3) Resource Adequacy Resources committed by the CAISO must maintain that commitment through Real-Time. In the event of a Forced Outage on a Resource Adequacy Resource committed in the Day-Ahead Market to provide Energy, the Scheduling Coordinator for the Modified Reserve Sharing LSE will have up to the next HASP bidding opportunity, plus one hour, to replace the lesser of: (i) the committed resource suffering the Forced Outage, (ii) the quantity of Energy committed in the Day-Ahead Market, or (iii) one hundred and seven (107) percent ~~(107%)~~ of the hourly forecast Demand.

* * *

40.5.2 Demand Forecast Accuracy

On a monthly basis, the CAISO will review Meter Data to evaluate the accuracy or quality of the hourly Day-Ahead Demand Forecasts submitted by the Scheduling Coordinator on behalf of Modified Reserve Sharing LSEs. If the CAISO determines, based on its review, that one or more Demand Forecasts materially under-forecasts the Demand of the Modified Reserve Sharing LSEs for whom the Scheduling Coordinator schedules, after accounting for weather adjustments, the CAISO will notify the Scheduling Coordinator of the deficiency and will cooperate with the Scheduling Coordinator and Modified Reserve

Sharing LSE(s) to revise its Demand Forecast protocols or criteria. If the material deficiency affects ten (10) hourly Demand Forecasts over a minimum of two (2) non-consecutive Business Days within a month, the CAISO may: (i) inform State of California authorities including, but not necessarily limited to, the California Legislature, and identify the Modified Reserve Sharing LSE(s) represented by the Scheduling Coordinator and (ii) assign to the Scheduling Coordinator responsibility for all tier 1 RUC charges as specified in Section 11.8.6.5 to address the uncertainty caused by the Scheduling Coordinator's deficient hourly Demand Forecasts until the deficiency is addressed.

* * *

40.6.2 Real-Time Availability

Resource Adequacy Resources that have received an IFM Schedule for Energy or Ancillary Services or a RUC Schedule for all or part of their Resource Adequacy Capacity must remain available to the CAISO through Real-Time for Trading Hours for which they receive an IFM or RUC schedule, including any Resource Adequacy Capacity of such resources that is not included in an IFM Schedule or RUC Schedule, except for Resource Adequacy Capacity that is subject to Section 40.6.4.

Short Start Units or Long Start Units that are Resource Adequacy Resources that do not have an IFM Schedule or a RUC Schedule for any of their Resource Adequacy Capacity for a given Trading Hour may be required to be available to the CAISO through Real-Time as specified in Sections 40.6.3 and 40.6.7. Resource Adequacy Resources with Resource Adequacy Capacity that is required to be available to the CAISO through Real-Time and does not have an IFM Schedule or a RUC Schedule for a given Trading Hour must submit to the RTM for that Trading hour: (a) Energy Bids and Self-Schedules for the full amount of the available Resource Adequacy Capacity, including capacity for which it has submitted Ancillary Services Bids or Submissions to Self-Provide Ancillary Services; and (b) Ancillary Services Bids and Submissions to Self-Provide Ancillary Services for the full amount of the available Ancillary Service-certified Resource Adequacy Capacity and for each Ancillary Service for which the resource is certified, including capacity for which it has submitted Energy Bids and Self-Schedules. The CAISO will insert Generated Bids in accordance with Section 40.6.8 for any Resource Adequacy ~~capacity~~Vapacity subject to the above requirements for which the resource has failed to submit the appropriate bids to the RTM.

The CAISO will honor submitted Energy Self-Schedules of Resource Adequacy Capacity unless the CAISO is unable to satisfy one hundred (100) percent ~~(100%)~~ of its Ancillary Services requirements. In such cases, the CAISO may curtail all or a portion of a submitted Energy Self-Schedule to allow Ancillary Service-certified Resource Adequacy Capacity to be used to meet the Ancillary Service requirements, as long as such curtailment does not lead to a real-time shortfall in energy supply. If the CAISO reduces a submitted Real-Time Energy Self-Schedule for Resource Adequacy Capacity when that capacity is needed to meet an Ancillary Services requirement, the Ancillary Service Marginal Price for that capacity will be calculated in accordance with Sections 27.1.2 and 40.6.1.

* * *

40.6.4.1 Registration of Use-Limited Resources

Hydroelectric Generating Units, Proxy Demand Resources, and Participating Load, including Pumping Load, are deemed to be Use-Limited Resources for purposes of this Section 40 and are not required to submit the application described in this Section 40.6.4.1. Scheduling Coordinators for other Use-Limited Resources, must provide the CAISO an application in the form specified on the CAISO Website requesting registration of a specifically identified resource as a Use-Limited Resource. This application shall include specific operating data and supporting documentation including, but not limited to~~;~~:

(1) a detailed explanation of why the resource is subject to operating limitations;

(2) historical data to show attainable MWhs for each 24-hour period during the preceding year, including, as applicable, environmental restrictions for NOx, SOx, or other factors; and

(3) further data or other information as may be requested by the CAISO to understand the operating characteristics of the unit.

Within five (5) Business Days after receipt of the application, the CAISO will respond to the Scheduling Coordinator as to whether or not the CAISO agrees that the facility is eligible to be a Use-Limited Resource. If the CAISO determines the facility is not a Use-Limited Resource, the Scheduling Coordinator may challenge that determination in accordance with the CAISO ADR Procedures.

* * *

40.6.8 Use Of Generated Bids

Prior to completion of the Day-Ahead Market, the CAISO will determine if Resource Adequacy Capacity subject to the requirements of Sections 40.5.1 or 40.6.1 and for which the CAISO has not received notification of an Outage has not been reflected in a Bid and will insert a Generated Bid for such capacity into the CAISO Day-Ahead Market. Prior to running the Real-Time Market, the CAISO will determine if Resource Adequacy Capacity subject to the requirements of Section 40.6.2 and for which the CAISO has not received notification of an Outage has not been reflected in a Bid and will insert a Generated Bid for such capacity into the Real-Time Market. If a Scheduling Coordinator for an RA Resource submits a partial bid for the resource's RA ~~capacity~~Capacity, the CAISO will insert a Generated Bid only for the remaining RA ~~capacity~~Capacity. In addition, the CAISO will determine if all dispatchable Resource Adequacy Capacity from Short Start Units, not otherwise selected in the IFM or RUC, is reflected in a Bid into the Real-Time Market and will insert a Generated Bid for any remaining dispatchable Resource Adequacy Capacity for which the CAISO has not received notification of an Outage. A Generated Bid for Energy will be calculated as provided in the Business Practice Manuals. A Generated Bid for Ancillary Services will equal zero dollars ($0/MW-hour). Notwithstanding any of the provisions of Section 40.6.8 set forth above, the CAISO will not insert any Bid in the Real-Time Market required under this Section 40 for a Resource Adequacy Resource that is a Use-Limited Resource unless the resource submits an Energy Bid and fails to submit an Ancillary Service Bid.

* * *

41.5.1 Day-Ahead And HASP RMR Dispatch

RMR Dispatches will be determined in accordance with the RMR Contract, the MPM-RRD process addressed in Sections 31 and 33 and through manual RMR Dispatch Notices to meet Applicable Reliability Criteria.

The CAISO will notify Scheduling Coordinators for RMR Units of the amount and time of Energy requirements from specific RMR Units in the Trading Day prior to or at the same time as the Day-Ahead Schedules and AS and RUC Awards are published, to the extent that the CAISO is aware of such requirements, through an RMR Dispatch Notice or flagged RMR Dispatch in the IFM Day-Ahead Schedule. The CAISO may also issue RMR Dispatch Notices after Market Close of the DAM and through

Dispatch Instructions flagged as RMR Dispatches in the Real-Time Market. The Energy to be delivered for each Trading Hour pursuant to the RMR Dispatch Notice an RMR Dispatch in the IFM or Real-Time shall be referred to as the RMR Energy. Scheduling Coordinators may submit Bids in the DAM or the HASP for RMR Units operating under Condition 1 of the RMR Contract in accordance with the bidding rules applicable to non-RMR Units. A Bid submitted in the DAM or the HASP for a Condition 1 RMR Unit shall be deemed to be a notice of intent to substitute a market transaction for the amount of MWh specified in each Bid for each Trading Hour pursuant to Section 5.2 of the RMR Contract. In the event the CAISO issues an RMR Dispatch Notice or an RMR Dispatch in the IFM or Real-Time Market for any Trading Hour, any MWh quantities cleared through Competitive ~~Constraint~~Constraints Run of the MPM-RRD shall be considered as a market transaction in accordance with the RMR Contract. RMR Units operating as Condition 2 RMR Units may not submit Bids until and unless the CAISO issues an RMR Dispatch Notice or issues an RMR Dispatch in the IFM, in which case a Condition 2 RMR Unit shall submit Bids in accordance with the RMR Contract in the next available market for the Trading Hours specified in the RMR Dispatch Notice or Day-Ahead Schedule.

* * *

43.1.2.1 LSE Opportunity to Resolve Collective Deficiency in Local Capacity Area Resources

Where the CAISO determines that a need for ICPM Capacity exists under Section 43.1.2, but prior to any designation of ICPM Capacity, the CAISO shall issue a Market Notice~~, no later than sixty (60) days before the beginning of the Resource Adequacy Compliance Year,~~ identifying the deficient Local Capacity Area and the quantity of capacity that would permit the deficient Local Capacity Area to comply with the Local Capacity Technical Study criteria provided in Section 40.3.1.1 and, where only specific resources are effective to resolve the Reliability Criteria deficiency, the CAISO shall provide the identity of such resources. Any Scheduling Coordinator may submit a revised annual Resource Adequacy Plan within thirty (30) days of the beginning of the Resource Adequacy Compliance Year demonstrating procurement of additional Local Capacity Area Resources consistent with the Market Notice issued under this Section. Any Scheduling Coordinator that provides such additional Local Capacity Area Resources consistent with the Market Notice under this Section shall have its share of any ICPM procurement costs under Section 43.7.3 reduced on a proportionate basis. If the full quantity of capacity is not reported to the CAISO under revised annual Resource Adequacy Plans in accordance with this Section, the CAISO may designate ICPM Capacity sufficient to alleviate the deficiency.

* * *

43.6.3 Market Payments

In addition to the ICPM Capacity Payment identified in Section 43.6, ICPM resources shall be entitled to retain any revenues received as a result of their selection in the CAISO Markets, provided, however, that ICPM resources are required to participate in the RUC process ~~through submission of~~will be optimized using a zero ($0) dollar RUC Availability Bid and are not eligible to receive compensation through the RUC process.

* * *

43.7.1 LSE Shortage Of Local Capacity Area Resources In Annual Plan

If the CAISO makes ICPM designations under Section 43.1.1.1 to address a shortage resulting from the failure of a Scheduling Coordinator for an LSE to identify sufficient Local Capacity Area Resources to meet its applicable Local Capacity Area capacity requirements in its annual Resource Adequacy Plan, then the CAISO shall allocate the total costs of the ICPM Capacity Payments for such ICPM designations (for the full term of those ICPM designations) pro rata to each Scheduling Coordinator for an LSE based on the ratio of its Local Capacity Area Resource Deficiency to the sum of the deficiency of Local Capacity Area Resources in the deficient Local Capacity Area(s) within a TAC Area. The Local Capacity Resource Area Deficiency under this Section shall be computed on a monthly basis and the ICPM Capacity Payments allocated based on deficiencies during the month(s) covered by the ICPM designation(s).

* * *

44. [NOT USED]

44.1 [NOT USED]

~~If, during the thirty (30) days following the effective date of this section, the CAISO concludes that a hardware or software failure or other event has compromised the ability of the CAISO to reliably and accurately operate the CAISO Controlled Grid and CAISO Balancing Authority Area and settle the CAISO's markets in accordance with the currently-effective version of the CAISO Tariff and Business~~

~~Practice Manuals, the CAISO may temporarily suspend the effectiveness of the currently-effective CAISO Tariff, or any part thereof, and operate under the terms and conditions of the ISO Tariff in effect on the day before the effective date of this section. In the event of such a suspension or partial suspension, the CAISO shall perform Settlements in accordance with a single version of the CAISO Tariff for the entire month in which the suspension occurred to the extent practicable. Upon restoration of the CAISO's ability to reliably and accurately operate the CAISO Controlled Grid and CAISO Balancing Authority Area and settle the CAISO's markets, the CAISO shall terminate such temporary suspension on the first of the month after a minimum of ten days' operations under the terms and conditions of the ISO Tariff in effect on the day before the effective date of this section unless Market Participants are required to change their process or systems, in which case a minimum of 30 days' operations are required.~~

44.2 [NOT USED]

~~The CAISO shall issue a Market Notice announcing any temporary suspension declared under Section 44.1 and stating the reason for the suspension. The suspension shall take effect at the time and date specified by the CAISO in the Market Notice. Within five (5) Business Days after the issuance of the Market Notice announcing the temporary suspension, the CAISO shall file a report with FERC describing the reasons for the temporary suspension and the estimated time by which the suspension will be terminated. The CAISO shall issue a subsequent Market Notice announcing the time and date on which the termination of the temporary suspension will be effective.~~

44.3 [NOT USED[

~~The CAISO shall not declare a suspension under Section 44.1 unless it has determined that there are no viable automated or manual work-arounds or other options that would restore the ability of the CAISO to reliably and accurately operate the CAISO Controlled Grid and CAISO Balancing Authority Area and settle the CAISO's markets in accordance with the CAISO Tariff and Business Practice Manuals while the underlying problem is resolved.~~

APPENDIX A

MASTER DEFINITION SUPPLEMENT

- Aggregated Participating Load

An aggregation at one or more Participating Load Locations, created by the CAISO in consultation with the relevant Participating Load, for the purposes of enabling ~~participating~~participation of the Participating Load in the CAISO Markets like Generation by submitting Supply Bids when offering Curtailable Demand and as non-Participating Load by submitting Demand Bids to consume in the Day-Ahead Market only.

* * *

- All Constraints Run (ACR)

The second optimization run of the MPM-RRD process through which all ~~transmission~~Transmission Constraints that are expected to be enforced in the market-clearing processes (IFM, RUC, STUC, RTUC and RTD) are enforced.

* * *

- Available Transfer Capability (ATC)

The available capacity of a given transmission path, in MW, after ~~allocation~~subtraction of ~~rights~~capacity associated with Existing Contracts and Transmission Ownership Rights~~, to~~ from that path's Operating Transfer Capability established consistent with CAISO and WECC transmission capacity rating guidelines, further described in Appendix L.

* * *

- CAISO Audit Committee

A committee of the CAISO Governing Board appointed pursuant to Article IV, Section 5 of the CAISO bylaws to (1) review the CAISO's annual independent audit, (2) report to the CAISO Governing Board on such audit, and (3) monitor compliance with the CAISO Code of Conduct.

* * *

- Competitive Constraints Run (CCR)

The first optimization run of the MPM-RRD process through which ~~all~~only pre-designated competitive ~~Constraints~~constraints are enforced.

* * *

- Congestion

A characteristic of the transmission system produced by a binding Transmission Constraint to the optimum economic dispatch to meet Demand such that the LMP, exclusive of Marginal Cost of Losses, at different Locations of the transmission system is not equal.

* * *

- ~~Constraints~~[NOT USED]

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

* * *

- Curtailable Demand

Demand from a Participating Load or Aggregated Participating Load that can be curtailed at the direction of the CAISO in the Real-Time Dispatch of the CAISO Controlled Grid. ~~Scheduling Coordinators with Curtailable Demand may offer it to the CAISO to meet Non-Spinning Reserve or Imbalance Energy.~~

* * *

- Day-Ahead Inter-SC Trade Period

~~-~~The period commencing seven (7) days prior to the applicable Trading Day and ending at ~~12:00 p.m.~~ noon on the day prior to that Trading Day, during which time the CAISO will accept Inter-SC Trades of Energy for the DAM from Scheduling Coordinators.

* * *

- Delivery Network Upgrades

~~-~~Transmission facilities at or beyond the Point of Interconnection, other than Reliability Network Upgrades, identified in the Interconnection Studies to relieve Transmission Constraints on the CAISO Controlled Grid.

* * *

- Estimated Aggregate Liability (EAL)

~~-~~The sum of a Market Participant's ~~or CRR Holder's~~ known and reasonably estimated potential liabilities for a specified time period arising from charges described in the CAISO Tariff, as provided for in Section 12.

* * *

- E-Tag

~~-~~An electronic tag associated with an Interchange ~~schedule~~Schedule in accordance with the requirements of WECC.

* * *

- Forward Scheduling Charge

The component of the Grid Management Charge that provides for the recovery of the CAISO's costs, including, but not limited to, the costs of providing the ability to Scheduling Coordinators to submit a Bid for Energy and Ancillary Services and the cost of processing accepted Ancillary Services Bids. The formula for determining the Forward Scheduling Charge is set forth in Appendix F, Schedule 1, Part A.

* * *

- Full Network Model (FNM)

~~-~~A computer-based model that includes all CAISO Balancing Authority Area transmission network (Load and Generating Unit) busses, ~~transmission~~Transmission Constraints, and Intertie busses between the CAISO Balancing Authority Area and interconnected Balancing Authority Areas. The FNM models the transmission facilities internal to the CAISO Balancing Authority Area as elements of a looped network and models the CAISO Balancing Authority Area Interties with interconnected Balancing Authority Areas in a radial fashion as specified in Section 27.5.

* * *

- 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 Utility Distribution Company or MSS Operator located in a PTO Service Territory. Gross Load shall exclude (1) Load with respect to which the Wheeling Access Charge is payable~~,~~; (2) Load that is exempt from the Access Charge pursuant to Section 4.1~~,~~ of Appendix I~~,~~; and (3) the portion of the Load of an individual retail customer of a Utility Distribution Company, Small Utility Distribution Company, 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~~customer's site through arrangements as authorized by Section 218 of the California Public Utilities Code; (b) is a qualifying small power production facility or qualifying cogeneration facility, as those terms are defined in the FERC's regulations implementing Section 201 of the Public Utility Regulatory Policies Act of 1978; and (c) secures Standby Service from a Participating TO under terms approved by a Local Regulatory Authority or FERC, as applicable, or can be curtailed concurrently with an Outage of the Generating Unit serving the Load. Gross Load forecasts consistent with filed Transmission Revenue Requirements will be provided by each Participating TO to the CAISO.

* * *

- HASP AS Award

~~-Awards~~An award for ~~imports~~an import of Ancillary Services established through the HASP.

* * *

- Henry Hub

~~-~~The pricing point for natural gas futures contracts~~ traded on the New York Mercantile Exchange (NYMEX).~~.

* * *

- Locational Marginal Price (LMP)

-The marginal cost ($/MWh) of serving the next increment of Demand at that PNode consistent with existing ~~transmission facility~~Transmission Constraints and the performance characteristics of resources.

* * *

- LSE

-Load-~~-~~ Serving Entity

* * *

- Market Participant

-An entity, including a Scheduling Coordinator, who either: (1) participates in the CAISO Markets through the buying, selling, transmission, or distribution of Energy, ~~Capacity~~capacity, or Ancillary Services into, out of, or through the CAISO Controlled Grid; or (2) is a CRR Holder or Candidate CRR Holder.

* * *

- Market Usage Charge

-The component of the Grid Management Charge that provides for the recovery of the CAISO's costs, including, but not limited to, the costs for processing Day-Ahead, Hour-Ahead Scheduling Process and Real-Time Bids, maintaining the Open Access Same-Time Information System, monitoring market performance, ensuring generator compliance with market rules as defined in the CAISO Tariff and the Business Practice Manuals, and determining LMPs. The formula for determining the Market Usage Charge is set forth in Appendix F, Schedule 1, Part A.

* * *

- Material Change In Financial Condition Version

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

-(a) a credit agency downgrade;

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

-(c) a bankruptcy filing;

-(d) insolvency;

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

~~-~~(f) any change in the financial condition of the Market Participant ~~or CRR Holder~~ which exceeds a five (5) percent ~~(5%)~~ reduction in the Market Participant's ~~or CRR Holder's~~ Tangible Net Worth or Net Assets for the Market ~~Participant or CRR Holder's~~Participant's preceding fiscal year, calculated in accordance with generally accepted accounting practices.

* * *

- Net Procurement

~~-~~The awarded amount (~~MWs~~MW) of a given Ancillary Service in the Day-Ahead, HASP, and Real-Time Markets, minus~~, (ii)~~ the amount of that Ancillary Service associated with payments rescinded pursuant to any of the provisions of Section 8.10.2.

* * *

- Non-Dynamic System Resource

~~-~~A System Resource that is not capable of submitting a Dynamic Schedule, or for which a Dynamic Schedule has not ~~be~~been submitted, which may be a Non-Dynamic Resource-Specific System Resource.

* * *

- Non-priced Quantity

~~-~~As set forth in Section 27.4.3, a quantitative value in a CAISO Market that may be adjusted by the SCUC or SCED in the CAISO market optimizations but that does not have an associated bid price submitted by a Scheduling Coordinator. The Non-priced Quantities that may be so adjusted are: Energy Self-Schedules, ~~transmission constraints~~Transmission Constraints, market energy balance constraints, Ancillary Service requirements, conditionally qualified and conditionally unqualified Ancillary Service self-provision, limits in RUC on minimum load energy, quick start capacity and minimum generation, Day-Ahead Energy Schedules resulting from the IFM, and estimated HASP Energy Self-Schedules used in RUC.

* * *

- Participating Generator

A Generator or other seller of Energy or Ancillary Services through a Scheduling Coordinator over the CAISO Controlled Grid (1) from a Generating Unit with a rated capacity of 1 MW or greater, ~~or~~(2) from a Generating Unit with a rated capacity of from 500 kW up to 1 MW for which the Generator elects to be a Participating Generator, or (3) from a Generating Unit providing Ancillary Services ~~and/~~or submitting Energy Bids through an aggregation arrangement approved by the CAISO, which has undertaken to be bound by the terms of the CAISO Tariff, in the case of a Generator through a Participating Generator Agreement or QF PGA.

* * *

- Participating TO (PTO) Service Territory

The area in which an IOU, a Local Public Owned Electric Utility, or federal power marketing authority that has turned over its transmission facilities and/or Entitlements to CAISO Operational Control is obligated to provide electric service to Load. A PTO Service Territory may be comprised of the Service Areas of more than one Local Publicly Owned Electric Utility, if they are operating under an agreement with the CAISO for aggregation of their MSS and their MSS Operator is designated as the Participating TO.

* * *

- PTO Service Territory

~~The area in which an IOU, a Local Public Owned Electric Utility, or federal power marketing authority that has turned over its transmission facilities and/or Entitlements to CAISO Operational Control is obligated to provide electric service to Load. A PTO Service Territory may be comprised of the Service Areas of more than one Local Publicly Owned Electric Utility, if they are operating under an agreement with the CAISO for aggregation of their MSS and their MSS Operator is designated as the Participating TO.~~

Participating TO Service Territory.

* * *

- Qualifying Facility (QF)

A qualifying cogeneration facility or ~~small~~ qualifying small power production facility, as defined in the Code of Federal Regulations, Title 18, Part 292 (18 C.F.R. § 292).

* * *

- Reliability Services Costs

The costs associated with services provided by the CAISO: 1) that are deemed by the CAISO as necessary to maintain reliable electric service in the CAISO Balancing Authority Area; and 2) whose costs are billed by the CAISO to the Participating TO pursuant to the CAISO Tariff. Reliability Services Costs include costs charged by the CAISO to a Participating TO associated with service provided under ~~an~~a Reliability Must-Run Contract, Exceptional Dispatches and Minimum Load Costs associated with units committed for local reliability requirements.

* * *

- RUC Zone

A forecast region representing a UDC or MSS Service Area, Local Capacity Area, or other collection of Nodes for which the CAISO has developed sufficient historical ~~CASIO~~CAISO Demand and relevant weather data to perform a Demand Forecast for such area, for which as further provided in Section 31.5.3.7 the CAISO may adjust the CAISO Forecast of CAISO Demand to ensure that the RUC process produces adequate local capacity procurement.

* * *

- Scheduling Coordinator ID Code (SCID)

~~-~~The ~~Bid component that indicates the~~ individual ~~identification~~Identification Code provided by the CAISO to the Scheduling Coordinator.

* * *

- Seasonal CRR Load Metric

~~-~~The MW level of Load that is exceeded only in ~~.05~~0.5 percent of the hours for each season and time of use period based on the LSE’s historical Load.

* * *

- Security Constrained Unit Commitment (SCUC)

~~-~~An algorithm performed by a computer program over ~~a multi-hour Time Horizon~~multiple hours that determines the Commitment Status and Day-Ahead Schedules, AS Awards, RUC Awards, HASP Intertie Schedules and Dispatch Instructions for selected resources and minimizes production costs (Start-Up, Minimum Load and Energy Bid Costs in IFM, HASP and RTM; Start-Up, Minimum Load and RUC Availability Bid Costs) while respecting the physical operating characteristics of selected resources and ~~transmission~~Transmission Constraints.

* * *

- Self-Commitment Period

The portion of a Commitment Period of a unit with an Energy Self- Schedule or a Submission to Self-Provide an Ancillary ~~Services~~Service, except for Non-Spinning Reserve self-provision by a Fast Start Unit. The Self-Commitment Period may include Time Periods without Energy Self-Schedules or AS self-provision if it is determined by inference that the unit must be on due to Minimum Run Time, Minimum Down Time, or Maximum Daily Start-Up constraints.

* * *

- Settlement Period

~~-~~For all CAISO 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.

* * *

- Settlements, Metering, And Client Relations Charge

~~-~~The component of the Grid Management Charge that provides for the recovery of the CAISO'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 CAISO’s Settlement, billing, and metering activities.

Because this is a fixed charge per Scheduling Coordinator ID Code, 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.

* * *

- Shadow Price

-The marginal value of relieving a particular ~~Constraint~~constraint.

* * *

- Short-Term Unit Commitment (STUC)

The Unit Commitment procedure run at approximately ~~T-~~52.5 minutes ~~for a Time Horizon of approximately five (5) hours. The STUC determines~~prior to the applicable Trading Hour to determine whether ~~some~~certain Medium Start Units need to be started early ~~enough~~ to meet the Demand within the STUC ~~Time Horizon~~forward-looking time period as described in Section 34.4 using the CAISO Forecast of CAISO Demand. The STUC produces a Unit Commitment solution for every 15-minute interval within the STUC ~~Time Horizon~~forward-looking time periods and issues binding Start-Up Instructions only as necessary.

* * *

- Simultaneous Feasibility Test (SFT)

-The process that the CAISO will conduct to ensure that allocated and auction CRRs do not exceed relevant ~~transmission system~~Transmission Constraints as described in Section 36.4.2 and further described in the Business Practice Manuals.

* * *

- Spinning Reserve Obligation

-The obligation of a Scheduling Coordinator to pay its share of costs incurred by the CAISO in procuring Spinning Reserve.

* * *

- System Resource

-A group of resources, single resource, or a portion of a resource located outside of the CAISO Balancing Authority Area, or an allocated portion of a Balancing Authority Area's portfolio of generating resources that are either a static Interchange ~~schedule~~Schedule or directly responsive to that Balancing Authority Area's Automatic Generation Control (AGC) capable of providing Energy and/or Ancillary Services to the CAISO Balancing Authority Area, provided that if the System Resource is providing Regulation to the CAISO it is directly responsive to AGC.

* * *

- ~~Time Horizon~~[NOT USED]

~~The time period to which a given CAISO Market optimization process applies. For the IFM and RUC the Time Horizon consists of each Trading Hour of the next Trading Day. For the HASP, the Time Horizon is 1.75 Trading Hours in fifteen-minute increments. For STUC the Time Horizon is 4.25 Trading Hours in fifteen-minute increments. For RTUC the Time Horizon is a variable number of fifteen-minute intervals that runs every fifteen minutes and covers 4 to 7 intervals. For the RTD, the Time Horizon is seven five-minute intervals span over thirty-five minutes.~~

* * *

- Tolerance Band

The permitted area of variation for performance requirements of resources used for various purposes as further provided in the CAISO Tariff. The Tolerance Band is expressed in terms of Energy (MWh) for Generating Units, System Units and imports from Dynamic System Resources for each Settlement Interval and equals the greater of the absolute value of: (1) five (5) MW divided by the number of Settlement Intervals per Settlement Period or (2) three (3) percent ~~(3%)~~ of the relevant Generating Unit's, Dynamic System Resource's or System Unit's maximum output (PMax), as registered in the Master File, divided by the number of Settlement Intervals per Settlement Period. The maximum output (PMax) of a Dynamic System Resource will be established by agreement between the CAISO and the Scheduling Coordinator representing the Dynamic System Resource on an individual case basis, taking into account the number and size of the generating resources, or allocated portions of generating resources, that comprise the Dynamic System Resource.

The Tolerance Band is expressed in terms of Energy (MWh) for Participating Loads for each Settlement Interval and equals the greater of the absolute value of: (1) five (5) MW divided by the number of Settlement Intervals per Settlement Period or (2) three (3) percent ~~(3%)~~ of the applicable HASP Intertie Schedule or CAISO Dispatch amount divided by the number of Settlement Intervals per Settlement Period.

The Tolerance Band shall not be applied to Non-Dynamic System Resources.

* * *

- Total Transfer Capability (TTC)

The amount of power that can be transferred over an interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre-Contingency and post-Contingency system conditions.

* * *

- Transmission Constraints

Physical and operational limits on the transfer of electric power through transmission facilities.

- Transmission Constraints Enforcement Lists

Consist of the post-Day-Ahead Market ~~transmission~~Transmission Constraints list and the pre-Day-Ahead Market ~~transmission~~Transmission Constraints list made available by the CAISO pursuant to Section 6.5.3.3. The post-Day-Ahead Market ~~transmission~~Transmission Constraints list consists of the ~~transmission~~Transmission Constraints enforced or not enforced in the Day-Ahead Market conducted on any given day. The pre-Day-Ahead Market ~~transmission~~Transmission Constraints the CAISO plans to enforce or not enforce in the next day's Day-Ahead Market. These lists will identify and include definitions for all Transmission Constraints, including contingencies and nomograms. The definition of the Transmission Constraint includes the individual elements that constitute the ~~transmission~~Transmission Constraint. Both lists will each contain the same data elements and will provide: the flowgate ~~Constraints~~constraints; transmission corridor ~~Constraints~~constraints; the Nomogram ~~Constraints~~constraints; and the list of ~~transmission~~Transmission Contingencies.

* * *

- Unaccounted For Energy (UFE)

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, and the total Measured 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.

* * *

- Unsecured Credit Limit

The level of credit established for a Market Participant~~ or CRR Holder~~ that is not secured by any form of Financial Security, as provided for in Section 12.

- 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.

* * *

- ~~WSCC Reliability Criteria Agreement~~ [NOT USED]

~~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.~~

APPENDIX B.4 PARTICIPATING LOAD AGREEMENT

* * *

ARTICLE IV

GENERAL TERMS AND CONDITIONS

4.3 **UDC Interruptible Load Programs.** Due to the CAISO's reliance on interruptible Loads to relieve System Emergencies and its contractual relationship with each UDC, the CAISO will not accept, and the Participating Load shall not submit, Bids~~,~~ from interruptible Loads which are subject to curtailment criteria established under existing retail tariffs, except under such conditions as may be specified in the CAISO Tariff.

4.6.1 **Submission of Bids and Self-provided Schedules**. When the Scheduling Coordinator on behalf of the Participating Load submits a Bid, the Participating Load will, by the operation of this Section 4.6.1, warrant to the CAISO that it has the capability to provide that service in accordance with the CAISO Tariff and that it will comply with CAISO Dispatch Instructions for the provision of the service in accordance with the CAISO Tariff.

* * *

APPENDIX B.6 MSA FOR METERED ENTITIES (MSA CAISOME)

* * *

ARTICLE I

DEFINITIONS AND INTERPRETATION

* * *

APPENDIX B.8 UTILITY DISTRIBUTION COMPANY OA (UDCOA)

* * *

ARTICLE III

GENERAL TERMS AND CONDITIONS

3.2 **Agreement Subject to CAISO Tariff.** This Operating Agreement shall be subject to the provisions of the CAISO Tariff which shall be deemed to be incorporated by reference herein, as the same may be changed or superseded from time to time pursuant to ~~Sections 22.10 and 22.4.3~~Section 15 of the CAISO Tariff. The Parties agree that they will comply with Section 4.4, and any other applicable provisions, of the CAISO Tariff.

3.4.1 **Compliance with CAISO Specifications and CAISO Operating Procedures.** The UDC will abide by and will perform all of the obligations under the CAISO Specifications and the CAISO Operating Procedures placed on UDCs in respect of all matters set forth therein as the same may be changed or superseded from time to time pursuant to the procedures set forth in Sections 22.~~10~~11 and 22.4.3 of the CAISO Tariff. In the event of any conflict or dispute over interpretation, the CAISO Tariff shall, at all times, take precedence over the CAISO Specifications and CAISO Operating Procedures. The CAISO shall not implement any reliability requirements, operating requirements or performance standards that would impose increased costs on the UDC without giving due consideration to whether the benefits of such requirements or standards are sufficient to justify such increased costs. In any proceeding concerning the cost recovery by the UDC of capital and operation and maintenance costs incurred to comply with CAISO Specifications and Operating Procedures, the CAISO shall, at the request of the UDC, provide specific information regarding the nature of, and need for, the CAISO-imposed requirements or standards to enable the UDC to use this information in support of cost recovery through rates and tariffs.

3.6 Single Point of Contact. The CAISO and the UDC shall each provide a single point of contact on a 24-hour, 7-day basis for the exchange of operational procedures and information. The Parties agree to exchange operational contact information in a format to be provided by the CAISO and completed as of the effective date of this Operating Agreement. Each Party shall provide the other Party ten (10) calendar days advance notice of updates to its operational contact information as that information is expected to change. In the case of a UDC that is also a Participating TO, there may be only one single point of contact required and, in the reasonable discretion of the CAISO, duplicative reporting requirements and functions may be waived. ~~Details of requirements relating to and the identity of the initial points of contact are set forth in Schedule 2.~~

SCHEDULE 2

[NOT USED]

~~OPERATIONAL CONTACT~~

~~CAISO:~~

~~Transmission Dispatcher~~

~~(Folsom):~~

~~Transmission Dispatcher~~

~~(Alhambra):~~

~~Shift Supervisor:~~

~~Director of Grid Operations:~~

~~City/State/Zip Code~~

~~Other CAISO Dispatch Operations Phones:~~

~~Generation Dispatcher~~

~~(Folsom)~~

~~Generation Dispatcher~~

~~(Alhambra)~~

~~**UDC:**~~

~~Name of Primary~~

~~Representative: ____~~

~~Name of Alternative~~

~~Representative: ____~~

~~Title: ______________________________~~

~~Address: ______________________________~~

~~City/State/Zip Code ______________________________~~

~~Email address: __________________~~

~~Phone: __________________~~

~~Fax: __________________~~

~~CONTACTS FOR NOTICES~~

~~UDC~~

~~Name of Primary Representative:~~ ______________________
~~Title:~~ ______________________
~~Address:~~ ______________________
~~City/State/Zip Code:~~ ______________________
~~Email Address:~~ ______________________
~~Phone:~~ ______________________
~~Fax No:~~ ______________________

~~Name of Alternative Representative:~~ ______________________
~~Title:~~ ______________________
~~Address:~~ ______________________
~~City/State/Zip Code:~~ ______________________
~~Email Address:~~ ______________________
~~Phone:~~ ______________________
~~Fax No:~~ ______________________

~~CAISO~~

~~Name of Primary Representative:~~ ______________________
~~Title:~~ ______________________
~~Address:~~ ______________________
~~City/State/Zip Code:~~ ______________________
~~Email Address:~~ ______________________
~~Phone:~~ ______________________
~~Fax No:~~ ______________________

~~Name of Alternative Representative:~~ ______________________
~~Title:~~ ______________________
~~Address:~~ ______________________
~~City/State/Zip Code:~~ ______________________
~~Email Address:~~ ______________________
~~Phone:~~ ______________________
~~Fax No:~~ ______________________

* * *

SCHEDULE 5

SYSTEM EMERGENCIES

The CAISO will notify the UDC's operational contact (Operations Shift Supervisor - Grid Control~~), as identified in Schedule 2,~~) of the emergency, including information regarding the cause, nature, extent, and potential duration of the emergency. The Operations Shift Supervisor will add any relevant data and will notify Distribution Operations. Distribution Operations will make the appropriate notifications within the UDC organization. The Operations Shift Supervisor and Distribution Control Shift Supervisor will then take such actions as are appropriate for the emergency.

The UDC will make requests for information from the CAISO regarding emergencies through the Operations Shift Supervisor, or the UDC Communication Coordinator may coordinate public information with the CAISO Communication Coordinator.

The UDC is required to estimate service restoration by geographic areas, and will use its call center and the media to communicate with customers during service interruptions. The UDC is also required to communicate the same information to appropriate state and local governmental entities. For transmission system caused outages the Operations Shift Supervisor will notify Distribution Operations Control Center of any information related to the outage such as cause, nature, extent, potential duration and customers affected.

Distribution Control and Grid Control Center logs, Electric Switching Orders and Energy Management System temporal data base will be used in preparation of outage reviews. These documents are defined as the chronological record of the operation of the activities which occur with the portion of the electrical system assigned to that control center. The log shall contain all pertinent information, including orders received and transmitted, relay operations, messages, clearances, accidents, trouble reports, daily switching program, etc.

The UDC will retain records in accordance with its record retention policy or practice, provided the records associated with this Operating Agreement are retained for a minimum of six years.

* * *

APPENDIX B.9 DSHBA OPERATING AGREEMENT (DSHBAOA)

* * *

3.4 Communication

The CAISO and the Host Balancing Authority shall each operate and maintain a 24-hour, 7-day control center with real-time scheduling and control functions. Appropriate control center staff will be provided by each Party who shall be responsible for operational communications and who shall have sufficient authority to commit and bind that Party. The CAISO and the Host Balancing Authority shall jointly develop communication procedures necessary to support scheduling and dispatch functions. ~~The Points of Contact and the procedures for insuring reliable communication are identified in Schedule 1~~The Parties agree to exchange operational contact information in a format to be provided by the CAISO and completed as of the effective date of this Agreement. Each Party shall provide the other Party ten (10) calendar days advance notice of updates to its operational contact information is expected to change.

* * *

11.4 Governing Law and Forum

Subject to ~~ICAA~~Section 11.5, this Agreement shall be deemed to be a contract made under and for all purposes shall be governed by and construed in accordance with the laws of the State of California. The Parties irrevocably consent that any legal action or proceeding arising under or relating to this Agreement shall be brought in any of the following forums, as appropriate: a court of the State of California or any federal court of the United States of America located in the State of California or, where subject to its jurisdiction, before the Federal Energy Regulatory Commission. No provision of this Agreement shall be deemed to waive the right of any Party to protest, or challenge in any manner, whether this Agreement, or any action or proceeding arising under or relating to this Agreement, is subject to the jurisdiction of the Federal Energy Regulatory Commission.

SCHEDULE 1
[NOT USED]

~~**POINTS OF CONTACT**~~
~~**[Section 3.4]**~~

~~**OPERATIONAL CONTACT**~~

~~**CAISO:**~~

~~Transmission Dispatcher (Folsom-Primary):~~	
~~Transmission Dispatcher (Alhambra-Backup):~~	
~~Generation Dispatcher (Folsom-Primary):~~	
~~Generation Dispatcher (Alhambra-Backup):~~	
~~Real-Time Scheduler (Folsom):~~	
~~Real-Time Scheduler (Alhambra):~~	
~~Pre Scheduler:~~	
~~Shift Supervisor:~~	
~~Control Room Fax:~~	
~~Outage Coordination:~~	
~~Fax:~~	
~~Director of Grid Operations:~~	
~~Address:~~	~~California ISO~~
	~~151 Blue Ravine Road~~
	~~P.O. Box 639014~~
	~~Folsom, CA 95763-9014~~

~~OPERATIONAL CONTACT~~

~~Host Balancing Authority:~~
~~Transmission Dispatcher (Primary):~~ ______________________________

~~Transmission Dispatcher (Backup):~~ ______________________________

~~Generation Dispatcher (Primary):~~ ______________________________

~~Generation Dispatcher (Backup):~~ ______________________________

~~Real-Time Scheduler:~~ ______________________________

~~Dispatch Supervisor:~~ ______________________________

~~Outage Coordination:~~ ______________________________

~~Fax:~~ ______________________________

~~Chief Dispatcher:~~ ______________________________

~~Address:~~ ______________________________
____
____

* * *

APPENDIX B.10 SMALL UTILITY DISTRIBUTION CO. OA (SUDCOA)

* * *

ARTICLE III
GENERAL TERMS AND CONDITIONS

3.4 Agreement Subject to CAISO Tariff. Notwithstanding anything to the contrary herein, the Parties agree that they will comply with Section 4.11 of the CAISO Tariff, and any other applicable provisions of the CAISO Tariff specifically referenced in this Operating Agreement. This Operating Agreement shall be subject to such provisions of the CAISO Tariff, which shall be deemed to be incorporated to the extent referenced herein, as the same may be changed or superseded from time to time pursuant to ~~Sections 22.10 and 22.4.3~~Section 15 of the CAISO Tariff. Nothing in this Operating Agreement shall affect in any way the authority of the CAISO to unilaterally make application to FERC for a change in the CAISO Tariff under Section 205 of the Federal Power Act, nor shall anything in this Operating Agreement affect the right of either Party to file a complaint under Section 206 of the Federal Power Act regarding the CAISO Tariff.

* * *

3.6.1 Compliance with CAISO Specifications and CAISO Operating Procedures. The SUDC will abide by and will perform all of the obligations under the CAISO Specifications identified in Schedule 6 and CAISO Operating Procedures identified in Schedule 9 in respect of all matters set forth therein as the same may be changed or superseded from time to time pursuant to the procedures set forth in Sections 22.~~10~~11 and 22.4.3 of the CAISO Tariff. In the event of any conflict or dispute over interpretation, those sections of the CAISO Tariff identified herein shall, at all times, take precedence over such CAISO Specifications and CAISO Operating Procedures. The CAISO shall not implement any reliability requirements, operating requirements or performance standards that would impose increased costs on the SUDC without giving due consideration to whether the benefits of such requirements or standards are sufficient to justify such increased costs. In any proceeding concerning the cost recovery by the SUDC of capital and operation and maintenance costs incurred to comply with CAISO Specifications and CAISO Operating Procedures, the CAISO shall to the extent practicable, at the request of the SUDC, provide specific information in a form that may be readily understood by the general public regarding the nature of, and need for, the CAISO-imposed requirements or standards to enable the SUDC to use this information in public hearings in support of cost recovery through rates and tariffs.

* * *

3.8 Single Point of Contact. The CAISO and the SUDC shall each provide a single point of contact for the exchange of operational procedures and information. ~~Details of requirements relating to and the identity of the initial points of contact are set forth in Schedule 3~~The Parties agree to exchange operational contact information in a format to be provided by the CAISO and completed as of the effective date of this Operating Agreement. Each Party shall provide the other Party ten (10) calendar days advance notice of updates to its operational contact information as that information is expected to change.

SCHEDULE 3

[NOT USED]

~~OPERATIONAL CONTACTS~~

~~CAISO:~~

~~Transmission Dispatcher (Folsom):~~ ________________

~~Transmission Dispatcher (Alhambra):~~ ________________

~~Generator Dispatcher: (Folsom-Primary)~~ ________________

~~Generator Dispatcher: (Alhambra-Backup)~~ ________________

~~Real Time Scheduler: (Folsom)~~ ________________

~~Real Time Scheduler: (Alhambra)~~ ________________

~~Pre Scheduler:~~ ________________

~~Shift Supervisor:~~ ________________

~~Control Room fax:~~ ________________

~~Outage Coordination:~~ ________________

~~Fax:~~ ________________

~~Director of Grid Operations:~~ ________________

~~SUDC:~~

~~Name of Operations Representative:~~ ________________

~~Title:~~ ________________

~~Address:~~ ________________

~~City/State/Zip Code:~~ ________________

~~Email address:~~ ________________

~~Phone:~~ ________________

~~Fax:~~ ________________

~~Name of Alternative Representative:~~ ________________

~~Title:~~ ________________

~~Email address:~~ ________________

~~Phone:~~ ________________

~~Fax:~~ ________________

~~**CONTACTS FOR NOTICES**~~

~~**SUDC**~~

~~Name of Primary~~
~~Representative:~~ ______________________

~~Title:~~ ______________________

~~Address:~~ ______________________

~~City/State/Zip Code:~~ ______________________

~~Email Address:~~ ______________________

~~Phone:~~ ______________________

~~Fax No:~~ ______________________

~~Name of Alternative~~
~~Representative:~~ ______________________

~~Title:~~ ______________________

~~Address:~~ ______________________

~~City/State/Zip Code:~~ ______________________

~~Email Address:~~ ______________________

~~Phone:~~ ______________________

~~Fax No:~~ ______________________

~~**CAISO**~~

~~Name of Primary~~
~~Representative:~~ ______________________________

~~Title:~~ ______________________________

~~Address:~~ ______________________________

~~City/State/Zip Code:~~ ______________________________

~~Email Address:~~ ______________________________

~~Phone:~~ ______________________________

~~Fax No:~~ ______________________________

~~Name of Alternative~~
~~Representative:~~ ______________________________

~~Title:~~ ______________________________

~~Address:~~ ______________________________

~~City/State/Zip Code:~~ ______________________________

~~Email Address:~~ ______________________________

~~Phone:~~ ______________________________

~~Fax No:~~ ______________________________

* * *

APPENDIX B.14 PROXY DEMAND RESOURCE AGREEMENT

* * *

4.3 Demand Response Provider Requirements. The Demand Response Provider must register with the CAISO through the Demand Response System and comply with all terms of the CAISO Tariff. A Demand Response Provider that aggregates the demand response of customers for utilities that distribute: (1) over four million MWh in the previous fiscal year must certify to the CAISO that its participation is not prohibited by the Local Regulatory Authority; or (2) four million MWh or less in the previous fiscal year must certify to the CAISO that its participation is permitted by the Local Regulatory Authority applicable to Demand Response Providers, and that it has satisfied all applicable rules and regulations of the Local Regulatory Authority. The Demand Response Provider must certify to the CAISO that any required bilateral agreements between the Demand Response Provider and the Load ~~Servicing~~ Serving Entities or other agreements required by the Local Regulatory Authority are fully executed.

APPENDIX C LOCATIONAL MARGINAL PRICE

* * *

B. The System Marginal Energy Cost Component of LMP

The SMEC shall be the same for each location throughout the system. SMEC is the sensitivity of the power balance constraint at the optimal solution. The power balance constraint ensures that the physical law of conservation of Energy (the sum of Generation and imports equals the sum of Demand, including exports and Transmission Losses) is accounted for in the network solution. For the designated reference location the CAISO will utilize a distributed Load Reference Bus for which constituent PNodes are weighted using the Reference Bus distribution factors. The Load distributed Reference Bus distribution factors are based on the Load Distribution Factors at each PNode that represents cleared Load in the Integrated Forward Market or forecast Load for MPM-RRD, RUC, HASP and RTM. In the Integrated Forward Market, in the event that the market is not able to clear based on the use of a distributed load Reference Bus, the CAISO will use a distributed generation Reference Bus for which the constituent nodes and the weights are determined economically within the running of the Integrated Forward Market based on available economic bids. In the event that the ~~ISO~~CAISO employs a distributed generation Reference Bus, it will notify Market Participants of which Integrated Forward Market runs required the use of this backstop mechanism. A distributed Load Reference Bus will be used for MPM-RRD, RUC, HASP and RTM regardless of whether a distributed Generation Reference Bus were used in the corresponding

Integrated Forward Market run. Once the Reference Bus is selected, the System Marginal Energy Cost is the cost of economically providing the next increment of Energy at the distributed Reference Bus, based on submitted Bids.

C. Marginal Congestion Component Calculation

The CAISO calculates the Marginal Costs of Congestion at each bus as a component of the bus-level LMP. The Marginal Cost of Congestion (MCCi) component of the LMP at bus i is calculated using the equation:

$$MCCi = -\left(\sum_{k=1}^{k} PTDFik * FSPk\right)$$

where:

- K is the number of thermal or interface ~~transmission constraints~~Transmission Constraints.

PTDFik is the Power Transfer Distribution Factor for the generator at bus i on interface k which limits flows across that constraint when an increment of power is injected at bus i and an equivalent amount of power is withdrawn at the Reference Bus. The industry convention is to ignore the effect of losses in the determination of PTDFs.

- FSPk is the constraint Shadow Price on interface k and is equivalent to the reduction in system cost expressed in $/MWh that results from an increase of 1MW of the capacity on interface k.

The Shadow Price at a given binding ~~constraint~~Transmission Constraint is the value per MW of the next increment of generation that would flow across the constrained path by relaxing the binding ~~constraint.~~Transmission Constraint. The PTDF of a PNode with respect to a transmission path (and direction on the path) measures the change in the power flow through the path (positive or negative, with respect to the designated direction on the path) as a result of an incremental injection at the Node, balanced by incremental change of Load at the Reference Bus.

* * *

G.1.1 Scheduling Point Prices

As described in Section 27.5.3, the CAISO's FNM includes a full model of the network topology of each IBAA. The CAISO will specify Resource IDs that associate Intertie Scheduling Point Bids and Schedules with supporting injection and withdrawal locations on the FNM. These Resource IDs may be specified by the CAISO based on the information available to it, or developed pursuant to a Market Efficiency Enhancement Agreement. Once these Resource IDs are established, the CAISO will determine Intertie Scheduling Point LMPs based on the injection and withdrawal locations associated with each Intertie Scheduling Point Bid and Schedule by the appropriate Resource ID. In calculating these LMPs the CAISO follows the provisions specified in Section 27.5.3 regarding the treatment of ~~transmission~~Transmission Constraints and losses on the IBAA network facilities. Unless otherwise required pursuant to an effective MEEA, the default pricing for all imports from the IBAA(s) to the CAISO Balancing Authority Area will be based on the SMUD/TID IBAA Import LMP and all exports to the IBAA(s) from the CAISO Balancing Authority Area will be based on the SMUD/TID IBAA Export LMP. The SMUD/TID IBAA Import LMP will be calculated based on modeling of supply resources that assumes all supply is from the Captain Jack substation as defined by WECC. The SMUD/TID IBAA Export LMP will be calculated based on the Sacramento Municipal Utility District hub that reflects Intertie distribution factors developed from a seasonal power flow base case study of the WECC region using an equivalencing technique that requires the Sacramento Municipal Utility District hub to be equivalenced to only the buses that comprise the aggregated set of load resources in the IBAA, with all generation also being retained at its buses within the IBAA. The resulting load distribution within each aggregated set of load resources within the IBAA defines the Intertie distribution factors for exports from the CAISO Balancing Authority Area.

* * *

APPENDIX E SUBMITTED ANCILLARY SERVICES DATA VERIFICATION
Verification of Submitted Data for Ancillary Services

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

* * *

APPENDIX F RATE SCHEDULES

Schedule 1
Grid Management Charge

Part A – Monthly Calculation of Grid Management Charge (GMC)
The Grid Management Charge consists of the following separate service charges: (1) the Core Reliability Services – Demand Charge, (2) the Core Reliability Services – Energy Exports Charge; (3) Energy Transmission Services – Net Energy Charge, (4) the Energy Transmission Services – Uninstructed Deviations Charge, (5) the Core Reliability Services/Energy Transmission Services – Transmission Ownership Rights Charge, (6) the Forward Scheduling Charge, (7) the Market Usage Charge, and (8) the Settlements, Metering, and Client Relations Charge

* * *

8. The rate for the Settlements, Metering, and Client Relations Charge will be fixed at $1000.00 per month, per Scheduling Coordinator ID Code (SCID) with ~~an~~a non-zero invoice value ~~other than $0.00~~where the non-zero value reflects market activity in the current Trading Month.

* * *

Part F ~~– Other Modifications to the Rates–~~[NOT USED].

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

~~1. The Forward Scheduling Charge assessed against Inter-SC Trades submitted by Pacific Gas and Electric Company solely in its role as Path 15 facilitator will be reduced by excluding sixty-five percent (65%) of the number of such Inter-SC Trades from the Forward Scheduling Charge. Such excluded Inter-SC Trades shall not be included in the denominator upon which the Forward Scheduling Charge is calculated.~~

* * *

Schedule 3
High Voltage Access Charge and Wheeling Access Charge

* * *

1.1 Objectives.

* * *

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

* * *

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 CAISO a charge for transmission service on the High Voltage Transmission Facilities included in the CAISO Controlled Grid. The charge will be based on the High Voltage Access Charge applicable to the TAC Area in which the point of delivery is located and the applicable Transition Charge. A UDC or MSS Operator that is also a Participating TO shall pay, or receive payment of, if applicable, the difference between (i) the High Voltage Access Charge and Transition Charge applicable to its transactions as a UDC or MSS Operator; and (ii) the disbursement of High Voltage Access Charge revenues to which it is entitled pursuant to Section 26.1.3 of the CAISO Tariff. At the conclusion of the 10-year TAC Transition Period, the Transition Charge will cease to apply, and the HVAC will be based on the single CAISO Grid-wide rate.

* * *

5.1 The Access Charge consists of a High Voltage Access Charge (HVAC) that is based on a TAC Area component and a CAISO Grid-wide component, a Transition 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. At the conclusion of the 10-year TAC Transition Period, the Transition Charge will cease to apply, and the HVAC will be based on the single CAISO Grid-wide rate.

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. At the conclusion of the 10-year TAC Transition Period, the Transition Charge will cease to apply, and the HVAC will be based on the single CAISO Grid-wide rate. Accordingly, the requirement for each Participating TO to divide its HVTRR into new and existing components shall cease to apply.

* * *

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 CAISO 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 CAISO 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).

$$ETRRI = \Sigma\ ETRR_A * \%_I GW$$

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

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

* * *

5.9 After the completion of the TAC 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, and the provisions of this Section 5 of this Schedule 3 referring to the calculation and application of the TAC Transition Charge shall cease to apply.

* * *

7. Limitation.

(a) During each year of the TAC Transition Period described in this Schedule 3, the increase in the total payment responsibility applicable to Gross Loads in the PTO Service Territory of an Original Participating TO attributable to the total for the year of (i) the amount applicable for the Original Participating TO under Section 26.5 of the CAISO 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 CAISO'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. At the conclusion of the ten-year TAC Transition Period, the Transition Charge and the obligations set forth in this Section 7 of this Schedule 3 will cease to apply, and the HVAC will be based on the single CAISO Grid-wide rate.

(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).

* * *

8.2 For service provided by a Participating TO prior to the TAC 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 TAC 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~~in the CAISO Market Invoice.

* * *

13.2 Updates to Low Voltage Access Charges. Unless otherwise agreed by the affected Participating TOs, a Non-Load-Serving Participating TO shall adjust its Low Voltage Access Charges and Low Voltage Wheeling Access Charges (1) when necessary to reflect any new transmission addition directly connecting a Participating TO to the Low Voltage Transmission Facilities of the Non-Load-Serving Participating TO; (2) on the date FERC makes effective a change to the Low Voltage Transmission Revenue Requirement of the Non-Load-Serving Participating TO; and (3) on the date FERC makes effective a change to Gross Load of a Participating TO directly connected to the Non-Load-Serving Participating TO. Using the Low Voltage Transmission Revenue Requirement accepted or authorized by FERC, consistent with Section 9 of this Schedule 3, for the Non-Load-Serving Participating TO, the ~~ISO~~CAISO will recalculate~~ on a monthly basis~~ the Low Voltage Access Charge applicable during such period. Revisions to the low voltage TRBA adjustment shall be made effective annually on January 1 based on the principal balance in the low voltage TRBA as of September 30 of the prior year and a forecast of Transmission Revenue Credits for the next year.

For service provided by a Non-Load-Serving Participating TO following the TAC Transition Date, any refund associated with a Non-Load-Serving Participating TO's Transmission Revenue Requirement that has been accepted by FERC, subject to refund, shall be provided as ordered by FERC. Such refund shall be invoiced ~~separately from~~in the CAISO Market Invoice.

If the Non-Load-Serving Participating TO withdraws one or more of its transmission facilities from the CAISO Operational Control in accordance with Section 3.4 of the Transmission Control Agreement, then the CAISO will no longer collect the TRR for that transmission facility through the CAISO's Access Charge effective upon the date the transmission facility is no longer under the Operational Control of the CAISO. The withdrawing Non-Load-Serving Participating TO shall be obligated to provide the CAISO 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 CAISO shall revise its transmission Access Charge to reflect the withdrawal of one or more transmission facilities from CAISO Operational Control.

* * *

APPENDIX G PRO FORMA RELIABILITY MUST-RUN CONTRACT
MUST-RUN SERVICE AGREEMENT

* * *

ARTICLE 1 DEFINITIONS

* * *

"Competitive ~~Constraint~~Constraints Run" is defined in Appendix A to the CAISO Tariff.

* * *

"Forced Outage" means a reduction in Availability of a Unit for which sufficient notice is not given to allow the outage to be factored into CAISO's day-ahead or hour-~~head~~ahead scheduling process.

ARTICLE 4 DISPATCH OF UNITS

4.1 CAISO's Right to Dispatch

* * *

(c) Except as needed for black start or voltage support required to meet local reliability needs, to meet operating criteria associated with the Potrero power plant, or as outlined below, CAISO may issue Dispatch Notices for Ancillary Services only if the available bids in Ancillary Service capacity markets do not provide sufficient capacity to meet CAISO's requirements.

(i) If the CAISO determines on a Trading Day that it needs additional Ancillary Service on that Trading Day, CAISO shall use the following procedures:

(A) CAISO shall communicate such needs to all Scheduling Coordinators as quickly as possible after such needs are identified.

(B) After completing (A), CAISO shall attempt to procure those additional Ancillary Services from the CAISO's Real-Time market (in the appropriate region if CAISO is procuring Ancillary Services on a regional basis) that have not closed, subject to the Bid Sufficiency Test described below.

(C) CAISO shall not issue a Dispatch Notice for Ancillary Services for any hour of the Trading Day before the earlier of (a) the time at which the real-time market for that hour closes or (b) if a Start-up would be required to provide the Ancillary Service, such earlier time as is necessary to comply with the applicable Start-up Lead Time and Ramping ~~Constraints~~constraints on Schedule A.

* * *

4.6 Limitations on CAISO's Right to Dispatch

CAISO's Dispatch Notice may not request Owner to, and Owner shall not be obligated to:

* * *

(iv) Start-up a Unit unless the time between the delivery of the Dispatch Notice requesting such Start-up and the commencement of the applicable Requested Operation Period equals at least the Start-up Lead Time for the Unit and the Dispatch Notice provides sufficient time to satisfy the Ramping ~~Constraint~~constraint of the Unit;

* * *

4.9 Test Dispatch Notices

(a) Availability Tests

* * *

(iii) The Test Dispatch Notice shall be marked "Availability Test Dispatch Notice." The Test Dispatch Notice shall specify a Requested Operation Period of four hours of continuous operations at the requested output plus any applicable Start-up Lead Time, time to satisfy Ramping ~~Constraints~~constraints and time for Shutdown (or for hydroelectric Units the time sufficient water is available, if that is less).

* * *

ARTICLE 5 DELIVERY OF ENERGY AND ANCILLARY SERVICES BY OWNER

5.1 Owner's Delivery of Energy and Ancillary Services

(a) Subject to the limits in this Agreement, and subject to the CAISO's Real-Time Dispatch instructions whether flagged as an RMR Dispatch or not, Owner shall provide service from the Units and Deliver the Requested MWh or Requested Ancillary Services in accordance with each Dispatch Notice. To the maximum extent practical, and except for regulation, Owner shall Deliver at each moment of each hour during the Requested Operation Period not less than the Requested MW or Requested Ancillary Services. If Owner has disputed a Dispatch Notice under Section 4.6 (i) (Minimum Load) (ii) (Minimum Run Time) (iii) (Minimum Off Time) (iv) (Start-up Lead Time and Ramping ~~Constraint~~constraint), or (v) (Unit Availability Limit) and such dispute is not resolved prior to the time for delivery, Owner will use reasonable efforts to comply with the Dispatch Notice, but shall not be liable to CAISO if it is unable to do so and Owner prevails in the dispute.

* * *

5.2 Substitution of Market Transactions for Dispatch Notices

(b) Owner shall give notice of its intent to substitute a Market Transaction through the submission of bids in the CAISO's Markets. Any dispatch level that clears the Competitive ~~Constraint~~Constraints Run of the MPM-RRD process through the submission of Economic Bids or Self-Schedules, and is reflected in the Day-Ahead Schedule or Real-Time Dispatch, shall be deemed a Market Transaction.

* * *

ARTICLE 6 MARKET TRANSACTIONS

6.1 Right To Engage In Market Transactions

* * *

(b) If CAISO issues a Dispatch Notice for a Unit operating under Condition 2, Owner shall submit bids in succeeding available Energy and Ancillary Services markets for the Requested Operation Period in accordance with the following requirements:

* * *

(v) Owner shall not bid Energy or Ancillary Services in excess of the quantities the Unit can provide during the Requested Operation Period given the Unit's ramp rates, Ramping ~~Constraints~~constraints and any other applicable operating limitations, with due allowance for a Unit's ability to change output during the Requested Operation Period.

APPENDIX L METHOD TO ASSESS AVAILABLE TRANSFER CAPABILITY

* * *

L.1.1 Available Transfer Capability (ATC) is a measure of the transfer capability in the physical transmission network resulting from system conditions and that remains available for further commercial activity over and above already committed uses.

ATC is defined as the Total Transfer Capability (TTC) less applicable operating Transmission Constraints due to system conditions and Outages (i.e., OTC), less the Transmission Reliability Margin (TRM) (which value is set at zero), less the sum of any unused existing transmission commitments (ETComm) (i.e., transmission rights capacity for ETC or TOR), less the Capacity Benefit Margin (CBM) (which value is set at zero), less the Scheduled Net Energy from Imports/Exports, less Ancillary Service capacity from Imports.

* * *

L.1.3 **Operating Transfer Capability (OTC)** is the TTC reduced by any operational Transmission Constraints caused by seasonal derates or Outages. CAISO Regional Transmission Engineers (RTE) determine OTC through studies using computer modeling.

* * *

L.1.6 **Transmission Reliability Margin (TRM)** is that amount of transmission transfer capability necessary reserved in the Day-Ahead Market (DAM) to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions. This DAM implementation avoids Real-Time Schedule curtailments that would otherwise be necessary due to:

- Demand Forecast error
- Anticipated uncertainty in transmission system topology
- Unscheduled flow
- Simultaneous path interactions
- Variations in Generation Dispatch
- Operating Reserve actions

The level of TRM for each Transmission Interface will be determined by CAISO Regional Transmission Engineers (RTE).

The ~~ISO~~CAISO does not use TRMs. The TRM value is set at zero.

L.1.7 **Capacity Benefit Margin (CBM)** is that amount of transmission transfer capability reserved for Load Serving Entities (LSEs) to ensure access to Generation from interconnected systems to meet generation reliability requirements. In the Day-Ahead Market, CBM may be used to provide reliable delivery of Energy to CAISO Balancing Authority Area Loads and to meet CAISO responsibility for resource reliability requirements in Real-Time. The purpose of this DAM implementation is to avoid Real-Time Schedule curtailments and firm Load interruptions that would otherwise be necessary. CBM may be used to reestablish Operating Reserves. CBM is not available for non-firm transmission in the CAISO Balancing Authority Area. CBM may be used only after:

- all non-firm sales have been terminated,
- direct-control Load management has been implemented,
- customer interruptible Demands have been interrupted,
- if the LSE calling for its use is experiencing a Generation deficiency and its transmission service provider is also experiencing transmission Constraints relative to imports of Energy on its transmission system.

The level of CBM for each Transmission Interface is determined by the amount of estimated capacity needed to serve firm Load and provide Operating Reserves based on historical, scheduled, and/or forecast data using the following equation to set the maximum CBM:

CBM = (Demand + Reserves) - Resources

Where:

- Demand = forecasted area Demand
- Reserves = reserve requirements
- Resources = internal area resources plus resources available on other Transmission Interfaces

The ~~ISO~~CAISO does not use CBMs. The CBM value is set at zero.

L.2 ATC Algorithm

The ATC algorithm is a calculation used to determine the transfer capability remaining in the physical transmission network and available for further commercial activity over and above already committed uses. The CAISO posts the ATC values in megawatts (MW) to OASIS in conjunction with the closing events for the Day-Ahead Market and HASP Real-Time Market process.

The following OASIS ATC algorithms are used to implement the CAISO ATC calculation for the ATC rated path (Transmission Interface):

OTC = TTC – CBM – TRM - Operating Constraints

ATC Calculation For Imports:
ATC = OTC – AS from Imports- Net Energy Flow - Hourly Unused TR Capacity.

ATC Calculation For Exports:
ATC = OTC – Net Energy Flow - Hourly Unused TR Capacity.

ATC Calculation For Internal Paths 15 and 26:
ATC = OTC – Net Energy Flow

The specific data points used in the ATC calculation are each described in the following table.

ATC	ATC MW	Available Transfer Capability, in MW, per Transmission Interface and path direction.
Hourly Unused TR Capacity	USAGE_MW	The sum of any unscheduled existing transmission commitments (scheduled transmission rights capacity for ETC or TOR), in MW, per path direction.
Scheduled Net Energy from Imports/Exports (Net Energy Flow)	ENE IMPORT MW	Total hourly net Energy flow for a specified Transmission Interface.
AS from Imports	AS IMPORT MW	Ancillary Services scheduled, in MW, as imports over a specified Transmission Interface.
OTC	OTC MW	Hourly Operating Transfer Capability of a specified Transmission Interface, per path direction, with consideration given to known Constraints and operating limitations.
Transmission Constraint	Constraint MW	Hourly ~~t~~Transmission Constraints, in MW, for a specific Transmission Interface and path direction.
CBM	CBM MW	Hourly Capacity Benefit Margin, in MW, for a specified Transmission Interface, per Path Direction.

TRM	TRM MW	Hourly Transmission Reliability Margin, in MW, for a specified Transmission Interface, per path direction.
TTC	TTC MW	Hourly Total Transfer Capability, in MW, of a specified Transmission Interface, per path direction.

The links to the CAISO Website where the actual ATC mathematical algorithms and other ATC calculational information are located are as follows:

Operating Procedures – Transmission
http://www.caiso.com/thegrid/operations/opsdoc/transmon/index.html

Operating Procedure - Total Transfer Capability Methodology
http://www.caiso.com/1bfe/1bfe98134fa0.pdf

Operating Procedure - System Operating Methodology
http://www.caiso.com/1c13/1c1390d420810.pdf

Business Practice Manual for Market Operations
https://bpm.caiso.com/bpm/bpm/version/000000000000005

OASIS – Transmission Information
http://oasis.caiso.com/mrtu-oasis

* * *

L.4 TTC – OTC Determination

All transfer capabilities are developed to ensure that power flows are within their respective operating limits, both pre-Contingency and post-Contingency. Operating limits are developed based on thermal, voltage and stability concerns according to industry reliability criteria (WECC/NERC) for transmission paths. The process for developing TTC or OTC is the same with the exception of inclusion or exclusion of operating Constraints based on system conditions being studied. Accordingly, further description of the process to determine either OTC or TTC will refer only to TTC.

* * *

APPENDIX M PROCEDURES FOR ADDRESSING PARALLEL FLOWS

The North American Electric Reliability Corporation's (NERC) Qualified Path Unscheduled Flow Relief for the Western Electricity Coordinating Council (WECC), Reliability Standard WECC-IRO-STD-006-0 filed by NERC in FERC Docket No. RR07-11-000 on March 26, 2007, and approved by ~~the Commission~~FERC on June 8, 2007, and any amendments thereto, are hereby incorporated and made part of this CAISO Tariff. See www.nerc.com for the current version of the NERC's Qualified Path Unscheduled Flow Relief Procedures for WECC.

* * *

APPENDIX O CAISO MARKET SURVEILLANCE COMMITTEE

* * *

9.4 Members of the MSC shall not engage in any market transactions other than in the performance of their duties under the CAISO ~~tariff~~Tariff.

APPENDIX P CAISO DEPARTMENT OF MARKET MONITORING

* * *

5 Duties of Market Monitor

* * *

5.1.7 Where the CAISO disagrees with DMM's recommendation pursuant to Section 5.1 of this Appendix P or DMM disagrees with a proposed market rule, tariff, or market design change, CAISO shall notify the FERC of such disagreement. Such notification shall be made in writing to FERC's Director of the Office of Energy Market Regulation~~ as part of a referral under Section 12 of this Appendix P~~.

* * *

5.5 Prohibition on Tariff Administration and Market Mitigation – DMM shall not participate in the administration of ~~CAISO's~~the CAISO Tariff or conduct prospective market mitigation.

5.5.1 For the purposes of Section 5.5 of this Appendix P, the term "prospective market mitigation" shall have the same meaning as provided in ~~Commission~~FERC Order No. 719, P 375.

* * *

5.5.3 DMM may provide the inputs required for CAISO to conduct any prospective mitigation that is otherwise permitted under this CAISO Tariff. Such inputs may include, but are not limited to, Default Energy Bids, identification of competitive ~~transmission~~Transmission Constraints, and cost calculations.

* * *

8. Information Sharing

* * *

8.1.4 DMM shall not provide any requested information or data that would impinge on ~~the Commission's~~FERC's confidentiality rules regarding referrals to ~~the Commission~~FERC pursuant to Sections 11 or 12 of this Appendix P.

8.5 Collection and Dissemination of Information Specific to a Market Participant
8.5.1 DMM may request that Market Participants or other entities whose activities may affect the operation of the CAISO Markets submit any information or data determined by DMM to be potentially relevant. This data will be subject to due safeguards to protect confidential and commercially sensitive data. Failures by Market Participants to provide such data shall be treated under Section 37~~.~~ of the CAISO Tariff. In the event of failures by other entities to provide such data, the CAISO 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 CAISO Markets or termination of any relevant CAISO agreements or certifications. Before any such action is taken, the CAISO Market Participant shall be provided the opportunity to respond in writing as to the reason for the alleged failure.

* * *

~~-~~8.6 Information related to the Transmission Planning Process in accordance with Section 24 of the CAISO Tariff the release of which DMM determines may harm competitive markets shall be deemed confidential.

* * *

11. Protocol on Referrals of Investigations to the Office of Enforcement.
11.1 DMM shall make a non-public referral to ~~the Commission~~FERC in all instances where DMM has reason to believe that a Market Violation has occurred. DMM's non-public referral shall provide sufficient credible information to warrant further investigation by ~~the Commission.~~FERC. Once DMM has obtained sufficient credible information to warrant referral to ~~the Commission~~FERC, DMM shall immediately refer the matter to ~~the Commission~~FERC and desist from independent action related to the alleged Market Violation. DMM may, however, continue to monitor for any repeated instances of the activity by the same or other entities, which would constitute new Market Violations. DMM shall respond to requests from ~~the Commission~~FERC for any additional information in connection with the alleged Market Violation it has referred.

* * *

11.1.3 Section 11.1 of this Appendix P notwithstanding, DMM may, but need not, refer to ~~the Commission~~FERC a suspected violation of the following provisions of Section 37 of this CAISO Tariff: 37.2.1; 37.2.2; 37.2.4; 37.3.1; 37.4.1, 37.4.2; 37.4.3; 37.5.2; 37.6.1; 37.6.2; and 37.6.3.

11.2 All referrals to ~~the Commission~~FERC of alleged Market Violations are to be in writing, whether transmitted electronically~~,~~ or by fax, mail, or courier. DMM may alert ~~the Commission~~FERC orally in advance of the written referral.

11.3 The referral is to be addressed to ~~the Commission's~~FERC's Director of the Office of Enforcement, with a copy also directed to both the Director of the Office of Energy Market Regulation and the General Counsel.

* * *

11.4.7 Any other information DMM believes is relevant and may be helpful to ~~the Commission~~FERC.

11.5 Following a referral to ~~the Commission~~FERC, DMM is to continue to notify and inform ~~the Commission~~FERC of any information that DMM learns of that may be related to the referral but DMM shall not undertake any investigative steps regarding the referral except at the express direction of ~~the Commission~~FERC or ~~Commission~~FERC Staff.

12 Protocol on Referrals of Perceived Market Design Flaws and Recommended Tariff Changes to the Office of Energy Market Regulation.
12.1 DMM is to make a referral to ~~the Commission~~FERC in all instances where it has reason to believe market design flaws exist that it believes could effectively be remedied by rule or tariff changes. DMM must limit distribution of its identifications and recommendations to CAISO, the CAISO Governing Board, and to ~~the Commission~~FERC in the event it believes broader dissemination could lead to exploitation of the market design flaw, with an explanation of why further dissemination should be avoided at that time.

12.2 All referrals to ~~the Commission~~FERC relating to perceived market design flaws and recommended tariff changes are to be in writing, whether transmitted electronically~~,~~ or by fax, mail, or courier. DMM may alert ~~the Commission~~FERC orally in advance of the written referral.

12.3 The referral should be addressed to ~~the Commission's~~FERC's Director of the Office of Energy Market Regulation, with copies directed to both the Director of the Office of Enforcement and the General Counsel.

* * *

12.4.4 Any other information DMM believes is relevant and may be helpful to ~~the Commission~~FERC.

12.5 Following a referral to ~~the Commission~~FERC, DMM is to continue to notify and inform ~~the Commission~~FERC of any additional information regarding the perceived market design flaw, its effects on the market, any additional or modified observations concerning the rule or tariff changes that could remedy the perceived design flaw, any recommendations made by DMM to CAISO, stakeholders, Market Participants or state commissions regarding the perceived design flaw, and any actions taken by CAISO regarding the perceived design flaw.

APPENDIX Q ELIGIBLE INTERMITTENT RESOURCES PROTOCOL (EIRP)

* * *

4.1 Hour-Ahead Forecast

The CAISO shall develop expert, independent hourly forecasts of Energy generation for 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 CAISO's discretion. The Scheduling Coordinator representing the Participating Intermittent Resource must use the hour-ahead forecast that is available ~~30~~thirty minutes prior to the deadline for submitting the HASP/RTM Bids. The CAISO shall use best efforts to provide reliable and timely forecasts. However, if the CAISO fails to deliver the hour-ahead forecast to the Scheduling Coordinator prior to ~~15~~fifteen minutes before the deadline for submitting HASP/RTM Bids, then the hour-ahead forecast shall be the most recent Energy forecast provided by the CAISO to the Scheduling Coordinator for the operating hour for which Bids are next due.

4.2 ~~Forecast Calibration~~[NOT USED]

~~The CAISO 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 11.12 of the CAISO Tariff.~~

* * *

APPENDIX U LARGE GENERATOR INTERCONNECTION PROCEDURES

* * *

11.3 Execution And Filing

At the time that the Interconnection Customer either returns the executed LGIA or requests the filing of an unexecuted LGIA as specified below, the Interconnection Customer shall provide the applicable Participating TO(s) and CAISO (A) reasonable evidence of continued Site Control or (B) posting to the applicable Participating TO(s) of $250,000, non-refundable additional security, which shall be applied toward future construction costs. At the same time, the Interconnection Customer also shall provide reasonable evidence that one or more of the following milestones in the development of the Large Generating Facility, at the Interconnection Customer election, has been achieved: (i) the execution of a contract for the supply or transportation of fuel to the Large Generating Facility; (ii) the execution of a contract for the supply of cooling water to the Large Generating Facility; (iii) execution of a contract for the engineering for, procurement of major equipment for, or construction of, the Large Generating Facility; (iv) execution of a contract for the sale of electric energy or capacity from the Large Generating Facility; or (v) application for an air, water, or land use permit.

The Interconnection Customer shall either: (i) execute ~~four~~ the appropriate number of originals of the tendered LGIA as specified in the directions provided by the CAISO and return ~~one~~them to the ~~applicable Participating TO(s) and two to the CAISO~~CAISO, as directed, for completion of the execution process; or (ii) request in writing that the applicable Participating TO(s) and CAISO file with FERC an LGIA in unexecuted form. The LGIA shall be considered executed as of the date that all Parties have signed the LGIA. As soon as practicable, but not later than ten (10) Business Days after receiving either the executed originals of the tendered LGIA (if it does not conform with a FERC-approved standard form of interconnection agreement) or the request to file an unexecuted LGIA, the applicable Participating TO(s) and CAISO shall file the LGIA with FERC, as necessary, together with an explanation of any matters as to which the Interconnection Customer and the applicable Participating TO(s) or CAISO disagree and support for the costs that the applicable Participating TO(s) propose to charge to the Interconnection Customer under the LGIA. An unexecuted LGIA should contain terms and conditions deemed appropriate by the applicable Participating TO(s) and CAISO for the Interconnection Request. If the Parties agree to proceed with design, procurement, and construction of facilities and upgrades under the agreed-upon terms of the unexecuted LGIA, they may proceed pending FERC action.

* * *

APPENDIX 3 INTERCONNECTION FEASIBILITY STUDY AGREEMENT

THIS AGREEMENT is made and entered into this day of , 20___ by and between ______________, a ________________ organized and existing under the laws of the State of , ("Interconnection Customer") and the California Independent System Operator Corporation, a California nonprofit public benefit corporation existing under the laws of the State of California, ("CAISO"). The Interconnection Customer and theCAISO each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Large Generating Facility or generating capacity addition to an existing Generating Facility consistent with the Interconnection Request submitted by the Interconnection Customer dated[1]; and

[footnote 1: This recital to be omitted if the Interconnection Customer has elected to forego the Interconnection Feasibility Study.]

WHEREAS, the Interconnection Customer desires to interconnect the Large Generating Facility with the CAISO Controlled Grid; and

WHEREAS, the Interconnection Customer has requested the CAISO to conduct or cause to be performed an Interconnection Feasibility Study to assess the feasibility of interconnecting the proposed Large Generating Facility.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agree as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated in the CAISO's FERC-approved Standard Large Generation

Interconnection Procedures ("LGIP") or the Master Definitions Supplement, Appendix A to the CAISO Tariff, as applicable.

2.0 The Interconnection Customer elects and the CAISO shall conduct or cause to be performed an Interconnection Feasibility Study consistent with the LGIP in accordance with the CAISO Tariff.

3.0 The scope of the Interconnection Feasibility Study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The Interconnection Feasibility Study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the Scoping Meeting. The CAISO reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the Interconnection Feasibility Study and as designated in accordance with Section 3.5.4 of the LGIP. If, after the designation of the Point of Interconnection pursuant to Section 3.5.4 of the LGIP, the Interconnection Customer modifies its Interconnection Request pursuant to Section 4.4 of the LGIP, the time to complete the Interconnection Feasibility Study may be extended.

5.0 The Interconnection Feasibility Study report shall provide the following information:

- preliminary identification of any circuit breaker short circuit capability limits exceeded on the Participating TO's electric system or the CAISO Controlled Grid as a result of the interconnection;
- preliminary identification of any thermal overload or voltage limit violations on the Participating TO's electric system or the CAISO Controlled Grid resulting from the interconnection;
- preliminary description and non-binding good faith estimate of cost and cost responsibility for and time for construction of the Participating TO's facilities required to interconnect the Large Generating Facility to the Participating TO's electric system or the CAISO Controlled Grid and to address the identified short circuit and power flow issues;
- preliminary identification of financial impacts, if any, on Local Furnishing Bonds; and
- expected results in the Interconnection System Impact Study.

* * *

APPENDIX V LARGE GENERATOR INTERCONNECTION AGREEMENT

STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT (LGIA)

[INTERCONNECTION CUSTOMER]

[PARTICIPATING TO]

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

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STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

[INTERCONNECTION CUSTOMER]

[PARTICIPATING TO]

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

* * *

ARTICLE 1. DEFINITIONS

* * *

NERC shall mean the North American Electric Reliability ~~Council~~Corporation or its successor organization.

ARTICLE 5. FACILITIES ENGINEERING, PROCUREMENT, AND CONSTRUCTION

* * *

5.4 Power System Stabilizers. The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council and in accordance with the provisions of Section 4.6.5.1 of the CAISO Tariff. The CAISO reserves the right to establish reasonable minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, the Interconnection Customer shall immediately notify the CAISO and the Participating TO and restore the Power System Stabilizers to operation as soon as possible~~ and in accordance with the Reliability Management System Agreement in Appendix G.~~. The CAISO shall have the right to order the reduction in output or disconnection of the Large Generating Facility if the reliability of the CAISO Controlled Grid would be adversely affected as a result of improperly tuned Power System Stabilizers. The requirements of this Article 5.4 shall not apply to wind generators of the induction type.

* * *

ARTICLE 9. OPERATIONS

9.1 General. Each Party shall comply with the Applicable Reliability Council requirements~~, and the Interconnection Customer shall execute the Reliability Management System Agreement of the Applicable Reliability Council attached hereto as Appendix G~~. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

* * *

9.6.2.1 Governors and Regulators. Whenever an Electric Generating Unit is operated in parallel with the CAISO Controlled Grid and the speed governors (if installed on the Electric Generating Unit pursuant to Good Utility Practice) and voltage regulators are capable of operation, the Interconnection Customer shall operate the Electric Generating Unit with its speed governors and voltage regulators in automatic operation. If the Electric Generating Unit's speed governors and voltage regulators are not capable of such automatic operation, the Interconnection Customer shall immediately notify the CAISO and the Participating TO and ensure that the Electric Generating Unit operates as specified in Article 9.6.2 through manual operation and that such Electric Generating Unit's reactive power production or absorption (measured in MVARs) are within the design capability of the Electric Generating Unit(s) and steady state stability limits. The Interconnection Customer shall restore the speed governors and voltage regulators to automatic operation as soon as possible~~ and in accordance with the Reliability Management System Agreement in Appendix~~

~~G.~~. If the Large Generating Facility's speed governors and voltage regulators are improperly tuned or malfunctioning, the CAISO shall have the right to order the reduction in output or disconnection of the Large Generating Facility if the reliability of the CAISO Controlled Grid would be adversely affected. The Interconnection Customer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the CAISO Controlled Grid or trip any Electric Generating Unit comprising the Large Generating Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Balancing Authority Area on a comparable basis.

* * *

ARTICLE 30. MISCELLANEOUS

* * *

30.11 Reservation of Rights. The CAISO and Participating TO shall each have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following Articles of this LGIA and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these Articles:

Recitals, 1, 2.1, 2.2, 2.3, 2.4, 2.6, 3.1, 3.3, 4.1, 4.2, 4.3, 4.4, 5 preamble, 5.4, 5.7, 5.8, 5.9, 5.12, 5.13, 5.18, 5.19.1, 7.1, 7.2, 8, 9.1, 9.2, 9.3, 9.5, 9.6, 9.7, 9.8, 9.10, 10.3, 11.4, 12.1, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24.3, 24.4, 25.1, 25.2, 25.3 (excluding subparts), 25.4.2, 26, 28, 29, 30, Appendix D, Appendix F, ~~Appendix G,~~ and any other Article not reserved exclusively to the Participating TO or the CAISO below.

The Participating TO shall have the exclusive right to make a unilateral filing with FERC to modify this LGIA pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following Articles of this LGIA and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these Articles:

2.5 , 5.1, 5.2, 5.3, 5.5, 5.6, 5.10, 5.11, 5.14, 5.15, 5.16, 5.17, 5.19 (excluding 5.19.1), 6, 7.3, 9.4, 9.9, 10.1, 10.2, 10.4, 10.5, 11.1, 11.2, 11.3, 11.5, 12.2, 12.3, 12.4, 24.1, 24.2, 25.3.1, 25.4.1, 25.5 (excluding 25.5.1), 27 (excluding preamble), Appendix A, Appendix B, Appendix C, and Appendix E.

The CAISO shall have the exclusive right to make a unilateral filing with FERC to modify this LGIA pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following Articles of this LGIA and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these Articles:

3.2 , 4.5, 11.6, 25.3.2, 25.5.1, and 27 preamble.

The Interconnection Customer, the CAISO, and the Participating TO shall have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this LGIA shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

* * *

IN WITNESS WHEREOF, the Parties have executed this LGIA in multiple originals, each of which shall constitute and be an original effective agreement among the Parties.

[Insert name of Participating TO]

By:

Title:

Date:

California Independent System Operator Corporation

By:

Title:

Date:

[Insert name of Interconnection Customer]

By:

Title:

Date:

Appendices to LGIA

Appendix A Interconnection Facilities, Network Upgrades and Distribution Upgrades

Appendix B Milestones

Appendix C Interconnection Details

Appendix D Security Arrangements Details

Appendix E Commercial Operation Date

Appendix F Addresses for Delivery of Notices and Billings

Appendix G ~~Reliability Management System Agreement~~[NOT USED]

Appendix H Interconnection Requirements for a Wind Generating Plant

* * *

APPENDIX G [NOT USED]

~~**To LGIA**~~

~~**Reliability Management System Agreement**~~

~~**RELIABILITY MANAGEMENT SYSTEM AGREEMENT**~~
~~**by and between**~~
~~**[TRANSMISSION OPERATOR]**~~
~~**and**~~
~~**[GENERATOR]**~~

~~THIS RELIABILITY MANAGEMENT SYSTEM AGREEMENT (the "Agreement"), is entered into this ____ day of ______________, 2002, by and between _________________________ (the "Transmission Operator") and _________________________ (the "Generator").~~

~~WHEREAS, there is a need to maintain the reliability of the interconnected electric systems encompassed by the WSCC in a restructured and competitive electric utility industry;~~

~~WHEREAS, with the transition of the electric industry to a more competitive structure, it is desirable to have a uniform set of electric system operating rules within the Western Interconnection, applicable in a fair, comparable and non-discriminatory manner, with which all market participants comply; and~~

~~WHEREAS, the members of the WSCC, including the Transmission Operator, have determined that a contractual Reliability Management System provides a reasonable, currently available means of maintaining such reliability.~~

~~NOW, THEREFORE, in consideration of the mutual agreements contained herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Transmission Operator and the Generator agree as follows:~~

~~**1. PURPOSE OF AGREEMENT**~~

~~The purpose of this Agreement is to maintain the reliable operation of the Western Interconnection through the Generator's commitment to comply with certain reliability standards.~~

~~**2. DEFINITIONS**~~

~~In addition to terms defined in the beginning of this Agreement and in the Recitals hereto, for purposes of this Agreement the following terms shall have the meanings set forth beside them below.~~

~~Control Area means an electric system or systems, bounded by interconnection metering and telemetry,~~

~~capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the Western Interconnection.~~

~~FERC means the Federal Energy Regulatory Commission or a successor agency.~~

~~Member means any party to the WSCC Agreement.~~

~~Party means either the Generator or the Transmission Operator and~~

~~Parties means both of the Generator and the Transmission Operator.~~

~~Reliability Management System or RMS means the contractual reliability management program implemented through the WSCC Reliability Criteria Agreement, the WSCC RMS Agreement, this Agreement, and any similar contractual arrangement.~~

~~Western Interconnection means the area comprising those states and provinces, or portions thereof, in Western Canada, Northern Mexico and the Western United States in which Members of the WSCC operate synchronously connected transmission systems.~~

~~Working Day means Monday through Friday except for recognized legal holidays in the state in which any notice is received pursuant to Section 8.~~

~~WSCC means the Western Systems Coordinating Council or a successor entity.~~

~~WSCC Agreement means the Western Systems Coordinating Council Agreement dated March 20, 1967, as such may be amended from time to time.~~

~~WSCC Reliability Criteria Agreement means the Western Systems Coordinating Council Reliability Criteria Agreement dated June 18, 1999 among the WSCC and certain of its member transmission operators, as such may be amended from time to time.~~

~~WSCC RMS Agreement means an agreement between the WSCC and the Transmission Operator requiring the Transmission Operator to comply with the reliability criteria contained in the WSCC Reliability Criteria Agreement.~~

~~WSCC Staff means those employees of the WSCC, including personnel hired by the WSCC on a contract basis, designated as responsible for the administration of the RMS.~~

~~3. TERM AND TERMINATION~~

~~3.1 Term. This Agreement shall become effective [thirty (30) days after the date of issuance of a final FERC order accepting this Agreement for filing without requiring any changes to this Agreement unacceptable to either Party. Required changes to this Agreement shall be deemed unacceptable to a Party only if that Party provides notice to the other Party within fifteen (15) days of issuance of the applicable FERC order that such order is unacceptable].~~
~~[Note: if the interconnection agreement is not FERC jurisdictional, replace bracketed language with: [on the later of: (a) the date of execution; or (b) the effective date of the WSCC RMS Agreement.]]~~

~~3.2 Notice of Termination of WSCC RMS Agreement. The Transmission Operator shall give the Generator notice of any notice of termination of the WSCC RMS Agreement by the WSCC or by the Transmission Operator within fifteen (15) days of receipt by the WSCC or the Transmission Operator of such notice of termination.~~

~~3.3 Termination by the Generator. The Generator may terminate this Agreement as follows:~~

~~(a) following the termination of the WSCC RMS Agreement for any reason by the WSCC or by the Transmission Operator, provided such notice is provided within forty-five (45) days of the termination of the WSCC RMS Agreement;~~
~~(b) following the effective date of an amendment to the requirements of the WSCC Reliability Criteria Agreement that adversely affects the Generator, provided notice of such termination is given within forty-five (45) days of the date of issuance of a FERC order accepting such amendment for filing, provided further that the forty-five (45) day period within which notice of termination is required may be extended by the Generator for an additional forty-five (45) days if the Generator gives written notice to the Transmission Operator of such requested extension within the initial forty-five (45) day period; or~~
~~(c) for any reason on one year's written notice to the Transmission Operator and the WSCC.~~

~~3.4 Termination by the Transmission Operator. The Transmission Operator may terminate this Agreement on thirty (30) days' written notice following the termination of the WSCC RMS Agreement for any reason by the WSCC or by the Transmission Operator, provided such notice is provided within thirty (30) days of the termination of the WSCC RMS Agreement.~~

~~3.5 Mutual Agreement. This Agreement may be terminated at any time by the mutual agreement of the Transmission Operator and the Generator.~~

~~4. COMPLIANCE WITH AND AMENDMENT OF WSCC RELIABILITY CRITERIA~~

~~4.1 Compliance with Reliability Criteria. The Generator agrees to comply with the requirements of the WSCC Reliability Criteria Agreement, including the applicable WSCC reliability criteria contained in Section IV of Annex A thereof, and, in the event of failure to comply, agrees to be subject to the sanctions applicable to such failure. Each and all of the provisions of the WSCC Reliability Criteria Agreement are hereby incorporated by reference into this Agreement as though set forth fully herein, and the Generator shall for all purposes be considered a Participant, and shall be entitled to all of the rights and privileges and be subject to all of the obligations of a Participant, under and in connection with the WSCC Reliability Criteria Agreement, including but not limited to the rights, privileges and obligations set forth in Sections 5, 6 and 10 of the WSCC Reliability Criteria Agreement.~~

~~4.2 Modifications to WSCC Reliability Criteria Agreement. The Transmission Operator shall notify the Generator within fifteen (15) days of the receipt of notice from the WSCC of the initiation of any WSCC process to modify the WSCC Reliability Criteria Agreement. The WSCC RMS Agreement specifies that such process shall comply with the procedures, rules, and regulations then applicable to the WSCC for modifications to reliability criteria.~~

~~4.3 Notice of Modifications to WSCC Reliability Criteria Agreement. If, following the process specified in Section 4.2, any modification to the WSCC Reliability Criteria Agreement is to take effect, the Transmission Operator shall provide notice to the Generator at least forty-five (45) days before such modification is scheduled to take effect.~~

~~4.4 Effective Date. Any modification to the WSCC Reliability Criteria Agreement shall take effect on the date specified by FERC in an order accepting such modification for filing.~~

~~4.5 Transfer of Control or Sale of Generation Facilities. In any sale or transfer of control of any generation facilities subject to this Agreement, the Generator shall as a condition of such sale or transfer require the acquiring party or transferee with respect to the transferred facilities either to assume the obligations of the Generator with respect to this Agreement or to enter into an agreement with the Control Area Operator in substantially the form of this Agreement.~~

~~5. SANCTIONS~~

~~5.1 Payment of Monetary Sanctions. The Generator shall be responsible for payment directly to the WSCC of any monetary sanction assessed against the Generator pursuant to this Agreement and the~~

~~WSCC Reliability Criteria Agreement. Any such payment shall be made pursuant to the procedures specified in the WSCC Reliability Criteria Agreement.~~

~~5.2 Publication. The Generator consents to the release by the WSCC of information related to the Generator's compliance with this Agreement only in accordance with the WSCC Reliability Criteria Agreement.~~

~~5.3 Reserved Rights. Nothing in the RMS or the WSCC Reliability Criteria Agreement shall affect the right of the Transmission Operator, subject to any necessary regulatory approval, to take such other measures to maintain reliability, including disconnection, which the Transmission Operator may otherwise be entitled to take.~~

~~6. THIRD PARTIES~~

~~Except for the rights and obligations between the WSCC and Generator specified in Sections 4 and 5, this Agreement creates contractual rights and obligations solely between the Parties. Nothing in this Agreement shall create, as between the Parties or with respect to the WSCC: (1) any obligation or liability whatsoever (other than as expressly provided in this Agreement), or (2) any duty or standard of care whatsoever. In addition, nothing in this Agreement shall create any duty, liability, or standard of care whatsoever as to any other party. Except for the rights, as a third-party beneficiary with respect to Sections 4 and 5, of the WSCC against Generator, no third party shall have any rights whatsoever with respect to enforcement of any provision of this Agreement. Transmission Operator and Generator expressly intend that the WSCC is a third-party beneficiary to this Agreement, and the WSCC shall have the right to seek to enforce against Generator any provisions of Sections 4 and 5, provided that specific performance shall be the sole remedy available to the WSCC pursuant to this Agreement, and Generator shall not be liable to the WSCC pursuant to this Agreement for damages of any kind whatsoever (other than the payment of sanctions to the WSCC, if so construed), whether direct, compensatory, special, indirect, consequential, or punitive.~~

~~7. REGULATORY APPROVALS~~

~~This Agreement shall be filed with FERC by the Transmission Operator under Section 205 of the Federal Power Act. In such filing, the Transmission Operator shall request that FERC accept this Agreement for filing without modification to become effective on the day after the date of a FERC order accepting this Agreement for filing. [This section shall be omitted for agreements not subject to FERC jurisdiction.]~~

~~8. NOTICES~~

~~Any notice, demand or request required or authorized by this Agreement to be given in writing to a Party shall be delivered by hand, courier or overnight delivery service, mailed by certified mail (return receipt requested) postage prepaid, faxed, or delivered by mutually agreed electronic means to such Party at the following address:~~

________: ________________________________

____

____

____

~~Fax:~~ ______________

________: ________________________________

____

____

____

~~Fax:~~ ______________

~~The designation of such person and/or address may be changed at any time by either Party upon receipt by the other of written notice. Such a notice served by mail shall be effective upon receipt. Notice~~

~~transmitted by facsimile shall be effective upon receipt if received prior to 5:00 p.m. on a Working Day, and if not received prior to 5:00 p.m. on a Working Day, receipt shall be effective on the next Working Day.~~

~~9. APPLICABILITY~~

~~This Agreement (including all appendices hereto and, by reference, the WSCC Reliability Criteria Agreement) constitutes the entire understanding between the Parties hereto with respect to the subject matter hereof, supersedes any and all previous understandings between the Parties with respect to the subject matter hereof, and binds and inures to the benefit of the Parties and their successors.~~

~~10. AMENDMENT~~

~~No amendment of all or any part of this Agreement shall be valid unless it is reduced to writing and signed by both Parties hereto. The terms and conditions herein specified shall remain in effect throughout the term and shall not be subject to change through application to the FERC or other governmental body or authority, absent the agreement of the Parties.~~

~~11. INTERPRETATION~~

~~Interpretation and performance of this Agreement shall be in accordance with, and shall be controlled by, the laws of the State of _______________ but without giving effect to the provisions thereof relating to conflicts of law. Article and section headings are for convenience only and shall not affect the interpretation of this Agreement. References to articles, sections and appendices are, unless the context otherwise requires, references to articles, sections and appendices of this Agreement.~~

~~12. PROHIBITION ON ASSIGNMENT~~

~~This Agreement may not be assigned by either Party without the consent of the other Party, which consent shall not be unreasonably withheld; provided that the Generator may without the consent of the WSCC assign the obligations of the Generator pursuant to this Agreement to a transferee with respect to any obligations assumed by the transferee by virtue of Section 4.5 of this Agreement.~~

~~13. SEVERABILITY~~

~~If one or more provisions herein shall be invalid, illegal or unenforceable in any respect, it shall be given effect to the extent permitted by applicable law, and such invalidity, illegality or unenforceability shall not affect the validity of the other provisions of this Agreement.~~

~~14. COUNTERPARTS~~

~~This Agreement may be executed in counterparts and each shall have the same force and effect as an original.~~

~~IN WITNESS WHEREOF, the Transmission Operator and the Generator have each caused this Reliability Management System Agreement to be executed by their respective duly authorized officers as of the date first above written.~~

____

~~By:~~ ____

~~Name:~~ ____

~~Title:~~ ~~____~~

~~____~~

~~By:~~ ~~____~~

~~Name:~~ ~~______________________________________~~

~~Title:~~ ~~____~~

* * *

APPENDIX X DYNAMIC SCHEDULING PROTOCOL (DSP)

* * *

8.4 All Dynamic ~~Scheduling~~Schedules and delivered Energy shall be subject to the standard CAISO Transmission Loss calculation associated with the particular Scheduling Point.

* * *

APPENDIX Y GIP FOR INTERCONNECTION REQUESTS

* * *

6.5.2.1 The On-Peak Deliverability Assessment.

The CAISO, in coordination with the applicable Participating TO(s), shall perform an On-Peak Deliverability Assessment for Interconnection Customers selecting Full Capacity Deliverability Status in their Interconnection Requests. The On-Peak Deliverability Assessment shall determine the Interconnection Customer's Generating Facility's ability to deliver its Energy to the CAISO Controlled Grid under peak load conditions, and identify preliminary Delivery Network Upgrades required to provide the Generating Facility with Full Capacity Deliverability Status. The preliminary Delivery Network Upgrades identified by the On-Peak Deliverability Assessment will be used to establish the maximum cost responsibility for Delivery Network Upgrades for each Interconnection Customer selecting Full Capacity Deliverability Status. Deliverability of a new Generating Facility will be assessed on the same basis as all other existing resources interconnected to the CAISO Controlled Grid.

The On-Peak Deliverability Assessment will identify the Network Upgrades that are required to enable the Generating Facility of each Interconnection Customer requesting Full Capacity Deliverability Status to meet the requirements for deliverability. Deliverability requires that the Generating Facility Capacity, as set forth in the Interconnection Request, can be delivered to the aggregate of Load on the CAISO Controlled Grid, consistent with Reliability Criteria, under CAISO Controlled Grid peak load and Contingency conditions, and assuming the aggregate output of existing Generating Facilities with established Net Qualifying Capacity values and other Generating Facilities in the Interconnection Study Cycle seeking Full Capacity Deliverability Status identified within the On-Peak Deliverability Assessment based on the effect of ~~transmission~~Transmission Constraints.

The On-Peak Deliverability Assessment will further perform an analysis to estimate the MW of deliverable generation capacity for the individual or Group Study if the highest cost Delivery Network Upgrade component were removed from the preliminary Delivery Network Upgrade plan, or, at the CAISO's sole discretion, if any other identified Delivery Network Upgrade component(s) were removed from the preliminary Delivery Network Upgrade plan. This information is provided to allow Interconnection Customers to address at the Results Meeting potential modifications under GIP Section 6.9.2 or change the Interconnection Request's Full Capacity Deliverability Status for purposes of financing under GIP Section 12.3.1.

The methodology for the On-Peak Deliverability Assessment will be published on the CAISO Website or, when effective, included in a CAISO Business Practice Manual. The On-Peak Deliverability Assessment does not convey any right to deliver electricity to any specific customer or Delivery Point.

The cost of all Delivery Network Upgrades identified in the On-Peak Deliverability Assessment as part of a Phase I Interconnection Study shall be estimated in accordance with GIP Section 6.4. The estimated costs of Delivery Network Upgrades identified in the On-Peak Deliverability Assessment shall be assigned to all Interconnection Requests selecting Full Capacity Deliverability Status based on the flow impact of each such Generating Facility on the Delivery Network Upgrades as determined by the Generation distribution factor methodology set forth in the On-Peak Deliverability Assessment methodology.

* * *

APPENDIX Z LGIA FOR INTERCONNECTION REQUESTS PROCESS UNDER THE GIP

LARGE GENERATOR INTERCONNECTION AGREEMENT (LGIA)

[INTERCONNECTION CUSTOMER]

[PARTICIPATING TO]

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

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NERC shall mean the North American Electric Reliability ~~Council~~Corporation or its successor organization.

ARTICLE 5. FACILITIES ENGINEERING, PROCUREMENT, AND CONSTRUCTION

* * *

5.16 Suspension. The Interconnection Customer reserves the right, upon written notice to the Participating TO and the CAISO, to suspend at any time all work associated with the construction and installation of the Participating TO's Interconnection Facilities, Network Upgrades, and/or Distribution Upgrades required under this LGIA, other than Network Upgrades identified in the Phase II Interconnection Study as common to multiple Generating Facilities, with the condition that the Participating TO's electrical system and the CAISO Controlled Grid shall be left in a safe and reliable condition in accordance with Good Utility Practice and the Participating TO's safety and reliability criteria and the CAISO's Applicable Reliability Standards. In such event, the Interconnection Customer shall be responsible for all reasonable and necessary costs which the Participating TO (i) has incurred pursuant to this LGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Participating TO's electric system during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which the Participating TO cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, the Participating TO shall obtain Interconnection Customer's authorization to do so.

The Participating TO shall invoice the Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work required under this LGIA pursuant to this Article 5.16, and has not requested the Participating TO to recommence the work or has not itself recommenced work required under this LGIA in time to ensure that the new projected Commercial Operation Date for the full Generating Facility Capacity of the Large Generating Facility is no more than three (3) years from the Commercial Operation Date identified in Appendix B hereto, this LGIA shall be deemed terminated and the Interconnection Customer's responsibility for costs will be determined in accordance with ~~Section~~Article 2.4~~ of this LGIA~~. The suspension period shall begin on the date the suspension is requested, or the date of the written notice to the Participating TO and the CAISO, if no effective date is specified.

* * *

APPENDIX BB STANDARD LARGE GENERATOR INTERCONNECTION AGREEMENT

Standard Large Generator Interconnection Agreement

for Interconnection Requests in a Serial Study Group that are tendered or execute a Large Generator Interconnection Agreement on or after July 3, 2010

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ARTICLE 18. INDEMNITY, CONSEQUENTIAL DAMAGES, AND INSURANCE

* * *

Appendices ....

* * *

ARTICLE 1. DEFINITIONS

* * *

NERC shall mean the North American Electric Reliability ~~Council~~Corporation or its successor organization.

* * *

ARTICLE 5. INTERCONNECTION FACILITIES ENGINEERING, PROCUREMENT, AND CONSTRUCTION

* * *

5.4 Power System Stabilizers. The Interconnection Customer shall procure, install, maintain and operate Power System Stabilizers in accordance with the guidelines and procedures established by the Applicable Reliability Council and in accordance with the provisions of Section 4.6.5.1 of the CAISO Tariff. The CAISO reserves the right to establish reasonable minimum acceptable settings for any installed Power System Stabilizers, subject to the design and operating limitations of the Large Generating Facility. If the Large Generating Facility's Power System Stabilizers are removed from service or not capable of automatic operation, the Interconnection Customer shall immediately notify the CAISO and the Participating TO and restore the Power System Stabilizers to operation as soon as possible~~ and in accordance with the Reliability Management System Agreement in Appendix G.~~. The CAISO shall have the right to order the reduction in output or disconnection of the Large Generating Facility if the reliability of the CAISO Controlled Grid would be adversely affected as a result of improperly tuned Power System Stabilizers. The requirements of this Article 5.4 shall apply to Asynchronous Generating Facilities in accordance with Appendix H.

* * *

ARTICLE 9. OPERATIONS

9.1 General. Each Party shall comply with the Applicable Reliability Council requirements~~, and the Interconnection Customer shall execute the Reliability Management System Agreement of the Applicable Reliability Council attached hereto as Appendix G~~. Each Party shall provide to the other Party all information that may reasonably be required by the other Party to comply with Applicable Laws and Regulations and Applicable Reliability Standards.

* * *

9.6.2.1 Governors and Regulators. Whenever an Electric Generating Unit is operated in parallel with the CAISO Controlled Grid and the speed governors (if installed on the Electric Generating Unit pursuant to Good Utility Practice) and voltage regulators are capable of operation, the Interconnection Customer shall operate the Electric Generating Unit with its speed governors and voltage regulators in automatic operation. If the Electric Generating Unit's speed governors and voltage regulators are not capable of such automatic operation, the Interconnection Customer shall immediately notify the CAISO and the Participating TO and ensure that the Electric Generating Unit operates as specified in Article 9.6.2 through manual operation and that such Electric Generating Unit's reactive power production or absorption (measured in MVARs) are within the design capability of the Electric Generating Unit(s) and steady state stability limits. The Interconnection Customer shall restore the speed governors and voltage regulators to automatic operation as soon as possible~~ and in accordance with the Reliability Management System Agreement in Appendix G.~~. If the Large Generating Facility's speed governors and voltage regulators are improperly tuned or malfunctioning, the CAISO shall have the right to order the reduction in output or disconnection of the Large Generating Facility if the reliability of the CAISO Controlled Grid would be adversely affected. The Interconnection Customer shall not cause its Large Generating Facility to disconnect automatically or instantaneously from the CAISO Controlled Grid or trip any Electric Generating Unit comprising the Large Generating Facility for an under or over frequency condition unless the abnormal frequency condition persists for a time period beyond the limits set forth in ANSI/IEEE Standard C37.106, or such other standard as applied to other generators in the Balancing Authority Area on a comparable basis.

* * *

ARTICLE 30. MISCELLANEOUS

* * *

30.11 Reservation of Rights. The CAISO and Participating TO shall each have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following Articles of this LGIA and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these Articles:

Recitals, 1, 2.1, 2.2, 2.3, 2.4, 2.6, 3.1, 3.3, 4.1, 4.2, 4.3, 4.4, 5 preamble, 5.4, 5.7, 5.8, 5.9, 5.12, 5.13, 5.18, 5.19.1, 7.1, 7.2, 8, 9.1, 9.2, 9.3, 9.5, 9.6, 9.7, 9.8, 9.10, 10.3, 11.4, 12.1, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24.3, 24.4, 25.1, 25.2, 25.3 (excluding subparts), 25.4.2, 26, 28, 29, 30, Appendix D, Appendix F, ~~Appendix G, ~~and any other Article not reserved exclusively to the Participating TO or the CAISO below.

The Participating TO shall have the exclusive right to make a unilateral filing with FERC to modify this LGIA pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following Articles of this LGIA and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these Articles:

2.5, 5.1, 5.2, 5.3, 5.5, 5.6, 5.10, 5.11, 5.14, 5.15, 5.16, 5.17, 5.19 (excluding 5.19.1), 6, 7.3, 9.4, 9.9, 10.1, 10.2, 10.4, 10.5, 11.1, 11.2, 11.3, 11.5, 12.2, 12.3, 12.4, 24.1, 24.2, 25.3.1, 25.4.1, 25.5 (excluding 25.5.1), 27 (excluding preamble), Appendix A, Appendix B, Appendix C, and Appendix E.

The CAISO shall have the exclusive right to make a unilateral filing with FERC to modify this LGIA pursuant to section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder with respect to the following Articles of this LGIA and with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation covered by these Articles:

3.2, 4.5, 11.6, 25.3.2, 25.5.1, and 27 preamble.

The Interconnection Customer, the CAISO, and the Participating TO shall have the right to make a unilateral filing with FERC to modify this LGIA pursuant to section 206 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder; provided that each Party shall have the right to protest any such filing by another Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this LGIA shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations thereunder, except to the extent that the Parties otherwise mutually agree as provided herein.

* * *

IN WITNESS WHEREOF, the Parties have executed this LGIA in multiple originals, each of which shall constitute and be an original effective agreement among the Parties.

[Insert name of Participating TO]

By: ______________________

Title: ______________________

Date:

California Independent System Operator Corporation

By: ______________________

Title: ______________________

Date:

[Insert name of Interconnection Customer]

By: ______________________

Title: ______________________

Date:

Appendices to LGIA

* * *

APPENDIX G [NOT USED]

~~**Appendix G**~~
~~**To LGIA**~~

~~**Reliability Management System Agreement**~~

~~**RELIABILITY MANAGEMENT SYSTEM AGREEMENT**~~
~~**by and between**~~
~~**[TRANSMISSION OPERATOR]**~~
~~**and**~~
~~**[GENERATOR]**~~

~~**THIS RELIABILITY MANAGEMENT SYSTEM AGREEMENT** (the "Agreement"), is entered into this _____ day of _______________, 2002, by and between ____________________________ (the "Transmission Operator") and ____________________________ (the "Generator").~~

~~**WHEREAS**, there is a need to maintain the reliability of the interconnected electric systems encompassed by the WSCC in a restructured and competitive electric utility industry;~~

~~**WHEREAS**, with the transition of the electric industry to a more competitive structure, it is desirable to have a uniform set of electric system operating rules within the Western Interconnection, applicable in a fair, comparable and non-discriminatory manner, with which all market participants comply; and~~

~~**WHEREAS**, the members of the WSCC, including the Transmission Operator, have determined that a contractual Reliability Management System provides a reasonable, currently available means of maintaining such reliability.~~

~~**NOW, THEREFORE**, in consideration of the mutual agreements contained herein, and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged, the Transmission Operator and the Generator agree as follows:~~

~~**1. PURPOSE OF AGREEMENT**~~

~~The purpose of this Agreement is to maintain the reliable operation of the Western Interconnection through the Generator's commitment to comply with certain reliability standards.~~

~~**2. DEFINITIONS**~~

~~In addition to terms defined in the beginning of this Agreement and in the Recitals hereto, for purposes of this Agreement the following terms shall have the meanings set forth beside them below.~~

~~**Control Area** means an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing to frequency regulation of the Western Interconnection.~~

~~**FERC** means the Federal Energy Regulatory Commission or a successor agency.~~

~~**Member** means any party to the WSCC Agreement.~~

~~**Party** means either the Generator or the Transmission Operator and~~

~~**Parties** means both of the Generator and the Transmission Operator.~~

~~**Reliability Management System** or **RMS** means the contractual reliability management program implemented through the WSCC Reliability Criteria Agreement, the WSCC RMS Agreement, this Agreement, and any similar contractual arrangement.~~

~~**Western Interconnection** means the area comprising those states and provinces, or portions thereof, in Western Canada, Northern Mexico and the Western United States in which Members of the WSCC operate synchronously connected transmission systems.~~

~~**Working Day** means Monday through Friday except for recognized legal holidays in the state in which any notice is received pursuant to Section 8.~~

~~**WSCC** means the Western Systems Coordinating Council or a successor entity.~~

~~**WSCC Agreement** means the Western Systems Coordinating Council Agreement dated March 20, 1967, as such may be amended from time to time.~~

~~**WSCC Reliability Criteria Agreement** means the Western Systems Coordinating Council Reliability Criteria Agreement dated June 18, 1999 among the WSCC and certain of its member transmission operators, as such may be amended from time to time.~~

~~**WSCC RMS Agreement** means an agreement between the WSCC and the Transmission Operator requiring the Transmission Operator to comply with the reliability criteria contained in the WSCC Reliability Criteria Agreement.~~

~~**WSCC Staff** means those employees of the WSCC, including personnel hired by the WSCC on a contract basis, designated as responsible for the administration of the RMS.~~

~~**3. TERM AND TERMINATION**~~

~~**3.1 Term.** This Agreement shall become effective [thirty (30) days after the date of issuance of a final FERC order accepting this Agreement for filing without requiring any changes to this Agreement unacceptable to either Party. Required changes to this Agreement shall be deemed unacceptable to a Party only if that Party provides notice to the other Party within fifteen (15) days of issuance of the applicable FERC order that such order is unacceptable].~~
~~[Note: if the interconnection agreement is not FERC jurisdictional, replace bracketed language with: [on the later of: (a) the date of execution; or (b) the effective date of the WSCC RMS Agreement.]]~~

~~**3.2 Notice of Termination of WSCC RMS Agreement.** The Transmission Operator shall give the Generator notice of any notice of termination of the WSCC RMS Agreement by the WSCC or by the Transmission Operator within fifteen (15) days of receipt by the WSCC or the Transmission Operator of such notice of termination.~~

~~**3.3 Termination by the Generator.** The Generator may terminate this Agreement as follows:~~
~~(a) following the termination of the WSCC RMS Agreement for any reason by the WSCC or by the Transmission Operator, provided such notice is provided within forty-five (45) days of the termination of the WSCC RMS Agreement;~~
~~(b) following the effective date of an amendment to the requirements of the WSCC Reliability Criteria Agreement that adversely affects the Generator, provided notice of such termination is given within forty-five (45) days of the date of issuance of a FERC order accepting such amendment for filing, provided further that the forty-five (45) day period within which notice of termination is required may be extended by the Generator for an additional forty-five (45) days if the Generator gives written notice to the Transmission Operator of such requested extension within the initial forty-five (45) day period; or~~
~~(c) for any reason on one year's written notice to the Transmission Operator and the WSCC.~~

~~**3.4 Termination by the Transmission Operator.** The Transmission Operator may terminate this Agreement on thirty (30) days' written notice following the termination of the WSCC RMS Agreement for any reason by the WSCC or by the Transmission Operator, provided such notice is provided within thirty (30) days of the termination of the WSCC RMS Agreement.~~

~~**3.5 Mutual Agreement.** This Agreement may be terminated at any time by the mutual agreement of the Transmission Operator and the Generator.~~

~~4. COMPLIANCE WITH AND AMENDMENT OF WSCC RELIABILITY CRITERIA~~

~~**4.1 Compliance with Reliability Criteria.** The Generator agrees to comply with the requirements of the WSCC Reliability Criteria Agreement, including the applicable WSCC reliability criteria contained in Section IV of Annex A thereof, and, in the event of failure to comply, agrees to be subject to the sanctions applicable to such failure. Each and all of the provisions of the WSCC Reliability Criteria Agreement are hereby incorporated by reference into this Agreement as though set forth fully herein, and the Generator shall for all purposes be considered a Participant, and shall be entitled to all of the rights and privileges and be subject to all of the obligations of a Participant, under and in connection with the WSCC Reliability Criteria Agreement, including but not limited to the rights, privileges and obligations set forth in Sections 5, 6 and 10 of the WSCC Reliability Criteria Agreement.~~

~~**4.2 Modifications to WSCC Reliability Criteria Agreement.** The Transmission Operator shall notify the Generator within fifteen (15) days of the receipt of notice from the WSCC of the initiation of any WSCC process to modify the WSCC Reliability Criteria Agreement. The WSCC RMS Agreement specifies that such process shall comply with the procedures, rules, and regulations then applicable to the WSCC for modifications to reliability criteria.~~

~~**4.3 Notice of Modifications to WSCC Reliability Criteria Agreement.** If, following the process specified in Section 4.2, any modification to the WSCC Reliability Criteria Agreement is to take effect, the Transmission Operator shall provide notice to the Generator at least forty-five (45) days before such modification is scheduled to take effect.~~

~~**4.4 Effective Date.** Any modification to the WSCC Reliability Criteria Agreement shall take effect on the date specified by FERC in an order accepting such modification for filing.~~

~~**4.5 Transfer of Control or Sale of Generation Facilities.** In any sale or transfer of control of any generation facilities subject to this Agreement, the Generator shall as a condition of such sale or transfer require the acquiring party or transferee with respect to the transferred facilities either to assume the obligations of the Generator with respect to this Agreement or to enter into an agreement with the Control Area Operator in substantially the form of this Agreement.~~

~~**5. SANCTIONS**~~

~~**5.1 Payment of Monetary Sanctions.** The Generator shall be responsible for payment directly to the WSCC of any monetary sanction assessed against the Generator pursuant to this Agreement and the WSCC Reliability Criteria Agreement. Any such payment shall be made pursuant to the procedures specified in the WSCC Reliability Criteria Agreement.~~

~~**5.2 Publication.** The Generator consents to the release by the WSCC of information related to the Generator's compliance with this Agreement only in accordance with the WSCC Reliability Criteria Agreement.~~

~~**5.3 Reserved Rights.** Nothing in the RMS or the WSCC Reliability Criteria Agreement shall affect the right of the Transmission Operator, subject to any necessary regulatory approval, to take such other measures to maintain reliability, including disconnection, which the Transmission Operator may otherwise be entitled to take.~~

~~**6. THIRD PARTIES**~~

~~Except for the rights and obligations between the WSCC and Generator specified in Sections 4 and 5, this Agreement creates contractual rights and obligations solely between the Parties. Nothing in this Agreement shall create, as between the Parties or with respect to the WSCC: (1) any obligation or liability whatsoever (other than as expressly provided in this Agreement), or (2) any duty or standard of care whatsoever. In addition, nothing in this Agreement shall create any duty, liability, or standard of care whatsoever as to any other party. Except for the rights, as a third-party beneficiary with respect to Sections 4 and 5, of the WSCC against Generator, no third party shall have any rights whatsoever with respect to enforcement of any provision of this Agreement. Transmission Operator and Generator expressly intend that the WSCC is a third-party beneficiary to this Agreement, and the WSCC shall have the right to seek to enforce against Generator any provisions of Sections 4 and 5, provided that specific performance shall be the sole remedy available to the WSCC pursuant to this Agreement, and Generator shall not be liable to the WSCC pursuant to this Agreement for damages of any kind whatsoever (other than the payment of sanctions to the WSCC, if so construed), whether direct, compensatory, special, indirect, consequential, or punitive.~~

~~**7. REGULATORY APPROVALS**~~

~~This Agreement shall be filed with FERC by the Transmission Operator under Section 205 of the Federal Power Act. In such filing, the Transmission Operator shall request that FERC accept this Agreement for filing without modification to become effective on the day after the date of a FERC order accepting this Agreement for filing. [This section shall be omitted for agreements not subject to FERC jurisdiction.]~~

~~**8. NOTICES**~~

~~Any notice, demand or request required or authorized by this Agreement to be given in writing to a Party shall be delivered by hand, courier or overnight delivery service, mailed by certified mail (return receipt requested) postage prepaid, faxed, or delivered by mutually agreed electronic means to such Party at the following address:~~

~~_______:~~ ____________________________

~~Fax: ______________~~

~~_______:~~

~~Fax: ______________~~

~~The designation of such person and/or address may be changed at any time by either Party upon receipt by the other of written notice. Such a notice served by mail shall be effective upon receipt. Notice transmitted by facsimile shall be effective upon receipt if received prior to 5:00 p.m. on a Working Day, and if not received prior to 5:00 p.m. on a Working Day, receipt shall be effective on the next Working Day.~~

~~9. APPLICABILITY~~

~~This Agreement (including all appendices hereto and, by reference, the WSCC Reliability Criteria Agreement) constitutes the entire understanding between the Parties hereto with respect to the subject matter hereof, supersedes any and all previous understandings between the Parties with respect to the subject matter hereof, and binds and inures to the benefit of the Parties and their successors.~~

~~10. AMENDMENT~~

~~No amendment of all or any part of this Agreement shall be valid unless it is reduced to writing and signed by both Parties hereto. The terms and conditions herein specified shall remain in effect throughout the term and shall not be subject to change through application to the FERC or other governmental body or authority, absent the agreement of the Parties.~~

~~11. INTERPRETATION~~

~~Interpretation and performance of this Agreement shall be in accordance with, and shall be controlled by, the laws of the State of _______________ but without giving effect to the provisions thereof relating to conflicts of law. Article and section headings are for convenience only and shall not affect the interpretation of this Agreement. References to articles, sections and appendices are, unless the context otherwise requires, references to articles, sections and appendices of this Agreement.~~

~~12. PROHIBITION ON ASSIGNMENT~~

~~This Agreement may not be assigned by either Party without the consent of the other Party, which consent shall not be unreasonably withheld; provided that the Generator may without the consent of the WSCC assign the obligations of the Generator pursuant to this Agreement to a transferee with respect to any obligations assumed by the transferee by virtue of Section 4.5 of this Agreement.~~

~~13. SEVERABILITY~~

~~If one or more provisions herein shall be invalid, illegal or unenforceable in any respect, it shall be given effect to the extent permitted by applicable law, and such invalidity, illegality or unenforceability shall not affect the validity of the other provisions of this Agreement.~~

~~14. COUNTERPARTS~~

~~This Agreement may be executed in counterparts and each shall have the same force and effect as an original.~~

~~**IN WITNESS WHEREOF**, the Transmission Operator and the Generator have each caused this Reliability Management System Agreement to be executed by their respective duly authorized officers as of the date first above written.~~

____

~~By:~~ ______________________________

~~Name:~~______________________________

~~Title:~~______________________________

____

~~By:~~ ______________________________

~~Name:~~______________________________

~~Title:~~______________________________

APPENDIX CC LARGE GENERATOR INTERCONNECTION AGREEMENT FOR INTERCONNECTION REQUESTS IN A QUEUE CLUSTER WINDOW

that are tendered a Large Generator Interconnection Agreement on or after July 3, 2010

* * *

ARTICLE 1. DEFINITIONS

* * *

NERC shall mean the North American Electric Reliability ~~Council~~Corporation or its successor organization.

* * *

ARTICLE 5. INTERCONNECTION FACILITIES ENGINEERING, PROCUREMENT, AND CONSTRUCTION

5.16 Suspension. The Interconnection Customer reserves the right, upon written notice to the Participating TO and the CAISO, to suspend at any time all work associated with the construction and installation of the Participating TO's Interconnection Facilities, Network Upgrades, and/or Distribution Upgrades required under this LGIA, other than Network Upgrades identified in the Phase II Interconnection Study as common to multiple Generating Facilities, with the condition that the Participating TO's electrical system and the CAISO Controlled Grid shall be left in a safe and reliable condition in accordance with Good Utility Practice and the Participating TO's safety and reliability criteria and the CAISO's Applicable Reliability Standards. In such event, the Interconnection Customer shall be responsible for all reasonable and necessary costs which the Participating TO (i) has incurred pursuant to this LGIA prior to the suspension and (ii) incurs in suspending such work, including any costs incurred to perform such work as may be necessary to ensure the safety of persons and property and the integrity of the Participating TO's electric system during such suspension and, if applicable, any costs incurred in connection with the cancellation or suspension of material, equipment and labor contracts which the Participating TO cannot reasonably avoid; provided, however, that prior to canceling or suspending any such material, equipment or labor contract, the Participating TO shall obtain Interconnection Customer's authorization to do so.

The Participating TO shall invoice the Interconnection Customer for such costs pursuant to Article 12 and shall use due diligence to minimize its costs. In the event Interconnection Customer suspends work required under this LGIA pursuant to this Article 5.16, and has not requested the Participating TO to recommence the work or has not itself recommenced work required under this LGIA in time to ensure that the new projected Commercial Operation Date for the full Generating Facility Capacity of the Large Generating Facility is no more than three (3) years from the Commercial Operation Date identified in Appendix B hereto, this LGIA shall be deemed terminated and the Interconnection Customer's responsibility for costs will be determined in accordance with ~~Section~~Article 2.4~~ of this LGIA~~. The suspension period shall begin on the date the suspension is requested, or the date of the written notice to the Participating TO and the CAISO, if no effective date is specified.

* * *