CALIFORNIA ISO

California Independent
System Operator

MARCH 13, 2006



The Honorable Magalie R. Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

RE: CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
DOCKET NO. ER06-____-000

THE INTERIM RELIABILITY REQUIREMENTS PROGRAM

Dear Secretary Salas

Pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d and Part 35 of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") regulations, 18 C.F.R. § 35 *et seq.* the California Independent System Operator, Inc. ("CAISO") respectfully submits for filing an original and five copies of an amendment to the ISO Tariff, to establish the Interim Reliability Requirements Program.[1] The Interim Reliability Requirements Program implements the Resource Adequacy programs being established by State authorities, including the California Public Utilities Commission ("CPUC") and other Local Regulatory Authorities ("LRAs"). The Interim Reliability Requirements Program is intended to remain effective until implementation of the Market Redesign and Technology Upgrade program ("MRTU") scheduled for Fall 2007.

## I. EXECUTIVE SUMMARY

The Commission has found that a Resource Adequacy program is a "critical element of any market design" that serves to, *inter alia,* meet reliability requirements, alleviate pressure on the spot market, establish appropriate price signals, and encourage infrastructure investment to support grid reliability and produce just and reasonable rates.[2]

In California, the Commission is acutely aware of the importance of Resource Adequacy in ensuring a stable electricity market and reliable power system operations. To prevent a failure such as the California Energy Crisis of 2000-01, the provisions of

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1 Capitalized terms not otherwise defined herein are used in the sense given in the Master Definitions Supplement, Appendix A to the ISO Tariff.

2 *See* Further Order on the California Comprehensive Market Design Proposal, 105 FERC ¶ 61,140 (2003) at PP 205, 214 (October 28, 2003).

the ISO Tariff ensuring system reliability must work in conjunction with the Resource Adequacy requirements established by the CPUC and other LRAs to provide a seamless process that ensures sufficient capacity will be available when and where it is needed to meet reliability requirements and to ensure stable operations of the power system at reasonable prices with less volatility.

On September 8, 2005, the California Legislature enacted Assembly Bill ("A.B.") 380, which required the CPUC, in consultation with the CAISO, to establish Resource Adequacy requirements for all Load Serving Entities within the CPUC's jurisdiction. In addition, A.B. 380 required local publicly owned utilities, as well as Load Serving Entities subject to the jurisdiction of the CPUC, to procure adequate resources to meet their peak demands and planning and operating reserves.

On October 27, 2005, the CPUC issued Decision (D.) 05-10-42 reaffirming and clarifying that entities under its jurisdiction would be required, by June 2006, to demonstrate that they have acquired capacity sufficient to serve their forecast retail customer load and a 15-17% Reserve Margin.

On February 9, 2006, the CAISO filed its comprehensive market redesign - the MRTU Tariff. With MRTU, the CAISO is proposing to end the current Commission-imposed "must-offer" obligation and transition to a capacity-based system in which the CPUC and other LRAs establish procurement requirements that require all Load Serving Entities within their jurisdiction to obtain sufficient resources to meet their Load with an adequate Reserve Margin and to ensure appropriate resources will be made available to the CAISO in the Day-Ahead Market, including the Residual Unit Commitment ("RUC") process, and in the Hour Ahead Scheduling Process ("HASP") and Real-Time Market based on a unit's operating characteristics. In addition to the CPUC's more developed Resource Adequacy Program, the CAISO expects that each LRA will establish a Resource Adequacy program that includes the following elements: (1) a Demand forecast; (2) Resource Adequacy standards, including appropriate Reserve Margins; (3) criteria for defining the resources that will qualify for, and how much capacity will count toward, meeting Reserve Margin requirements; (4) plans - Annual and Monthly - of how that Demand will be served; (5) requirements on how the resources will be available to the CAISO that are consistent with MRTU Tariff requirements; and (6) a program to ensure compliance so that the CAISO system Demand can be met and that no Load Serving Entity inappropriately leans on other Load Serving Entities. MRTU, however, is not expected to be implemented before November 2007.

The Interim Reliability Requirements Program adjusts the CAISO's existing systems to incorporate the Resource Adequacy programs adopted by the CPUC and other LRAs in accordance with AB 380 for the period between June 2006 and the implementation of MRTU. To the extent feasible, the CAISO will operate the grid relying on resources procured to meet Resource Adequacy requirements. The FERC must-offer obligation is retained only as a backstop to ensure system reliability and prevent economic or physical withholding of resources. Importantly, the fundamental operation of the FERC must-offer requirement -- who it applies to, what is paid, and by whom -- does not change under the Interim Reliability Requirements Program.

Because the CAISO seeks to conform to the new Resource Adequacy policies adopted by the CPUC on a timely basis and also because the modifications proposed herein have already been subject to substantial stakeholder input, the CAISO requests an effective date of May 12, 2006, sixty days from the date of this filing, for the provisions regarding submission of Resource Adequacy Plans and Supply Plans and May 31, 2006 for the remainder of the proposed tariff sheets, coincident with the CPUC requirements.

## II. STATEMENT OF ISSUE

Whether the Interim Reliability Requirements Program proposed by the CAISO is just and reasonable.

## III. BACKGROUND AND STATEMENT OF REASONS FOR FILING

### A. The CAISO's Role in Resource Adequacy

A.B. 380[3] directed the CPUC to establish, in consultation with the CAISO, new Resource Adequacy requirements for Load Serving Entities that are under the jurisdiction of the CPUC. As described in A.B. 380, the CPUC's Resource Adequacy program must,

> Ensure that adequate physical generating capacity dedicated to serving all load requirements is available to meet peak demand and planning and operating reserves, at or deliverable to locations and at times as may be necessary to ensure local area reliability and system reliability, at just and reasonable rates.[4]

In addition, A.B. 380 required each of California's local publicly owned electric utilities to "procure resources that are adequate to meet its planning reserve margin and peak demand and operating reserves, sufficient to provide reliable electric service to its customers."[5]

At the November 21, 2002 meeting of the CAISO Board of Governors, the Board directed CAISO management to defer to State efforts to address the broader issue of Resource Adequacy. In addition, the Board directed management to actively engage in the CPUC proceeding regarding the establishment of procurement rules for the State's Investor Owned Utilities ("IOUs"). At that meeting, the Board acknowledged the State's legitimate and primary role in addressing matters related to Resource Adequacy or,

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3 CAL. PUB. UTIL. CODE § 380 (2006).

4 *Id.*

5 Cal. Pub. Util. CODE § 9620 (2006).

more specifically, the obligations of Load Serving Entities to procure enough resources to serve their Load plus reserves.

In the recent MRTU filing, CAISO witness Mark Rothleder testified with respect to the CAISO's responsibility:

> the CAISO's role can be divided into three components: (1) assisting in the implementation of rules adopted by the CPUC and Local Regulatory Authorities, including providing technical input, (2) implementing rules over suppliers outside the jurisdiction of the Local Regulatory Authorities, and (3) ensuring the objective of Resource Adequacy to have resources available when and where needed is realized by providing for coordination of the rules adopted by the CPUC and other Local Regulatory Authorities with the design of the CAISO Markets and Bidding practices and the physical realities of the CAISO's system through appropriate MRTU Tariff provisions applicable to Scheduling Coordinators.[6]

As described below, the Interim Reliability Requirements Program achieves these objectives by deferring to the criteria established by the CPUC and other LRAs in key areas such as establishment of the Reserve Margin, development of Demand Forecasts, and determination of Qualifying Capacity. The resources procured under the programs developed by State and Local authorities are then made available to the CAISO though the CAISO's bidding and scheduling practices. Only in the event that insufficient supply at the system or local level is procured and made available under the State and Local programs does the CAISO utilize the existing FERC must-offer obligation or engage in backstop procurement to maintain grid reliability.

## B. CPUC Resource Adequacy Proceeding

As a result of the California Energy Crisis, the CPUC opened a proceeding in October 2001 to establish the means by which the IOUs could resume full resource procurement responsibilities. In subsequent decisions, the CPUC allocated the contracts entered into by the California Department of Water Resources during the crisis and addressed short-term procurement.

In January 2004, the CPUC issued D.04-01-050, which adopted key policies for Resource Adequacy requirements applicable to the IOUs as well as to Energy Service Providers ("ESPs") and Community Choice Aggregations operating within the IOUs' service territories.[7] These policies included, among other things, a requirement that each Load Serving Entity meet Demand plus a Planning Reserve Margin of 15-17% for each "summer" month, defined as May through September. Each Load Serving Entity was required to meet this obligation no later than January 1, 2008 through a gradual phase-in, with interim benchmarks that became effective in 2005. In addition, each Load Serving Entity was required to forward contract 90% of its summer (May through

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6 Direct Testimony of Mark Rothleder in Docket No. ER06-615-000 at p. 9.

7 California Pub. Util. Comm'n Decision 04-01-050 (January 22, 2004).

September) peaking needs (loads plus planning reserves) a year in advance, subject to adjustment if implementation would result in significantly increased costs or foster collusion and/or the exercise of market power in the Western energy markets; and (4) the 5% target limitation on utilities' reliance on the spot market (*i.e.*, Day-Ahead, Hour-Ahead, and Real-Time Energy) to meet their Energy needs was continued in effect.

Following D.04-01-050, the CPUC instituted a series of workshops beginning in March 2004 to address various technical, methodological, definitional, and procedural issues, including Load forecasting protocols, resource counting conventions, and deliverability. The Workshop Report on Resource Adequacy Issues (Workshop Report) was issued on June 15, 2004.[8]

On July 8, 2004, an Administrative Law Judge's Ruling Requesting Additional Comments on Resource Adequacy Issues ("July 8 Ruling") was issued focusing on the reserve deadlines for the reserve and forward contracting requirements in D.04-01-050. The July 8 Ruling also noted that in an April 28, 2004 letter to CPUC President Michael Peevey, Governor Schwarzenegger indicated that the "[CPUC's] phase-in date [for Resource Adequacy] of 2008 is too slow" and described President Peevey's concurrence with the Governor's assessment, and indicated that the phase-in "needs to be accelerated to ensure system reliability."[9] Finally, the July 8 Ruling noted that the Joint Opening Statement of President Peevey and Commissioner John Geesman of the California Energy Commission at the April 30 prehearing conference indicated that "we will look closely not only at refinement of the existing requirements, but also their acceleration as requested by the Governor."[10] The ruling invited comments and replies on: (1) accelerating the phase-in of the full planning reserve margin from January 1, 2008 to June 1, 2006 and (2) how the year-round 15%-17% reserve requirement and the seasonal 90% forward contracting requirement adopted in D.04-01-050 interact.[11]

The CPUC issued D.04-10-035 on October 28, 2004.[12] That decision provided clarification with respect to the Resource Adequacy policy framework adopted in D.04-01-50, identified issues to be resolved in further proceedings, and established certain procedural processes to be undertaken in a "Phase 2" proceeding.[13] D.04-10-035 also, *inter alia,* (1) adopted the accelerated June 1, 2006 implementation schedule advocated by Governor Schwarzenegger; (2) clarified that the Planning Reserve Margin must be satisfied for all months, not just summer months; (3) imposed a requirement on each Load Serving Entity to demonstrate 100% procurement of its Demand and Planning

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8 California Pub. Util. Comm'n, Workshop Report on Resource Adequacy Prepared by ALJ Michelle Cooke, Rulemaking Docket Nos. 04-04-003, 01-10-024 (June 15, 2004).

9 April 28, 2004 letter of Governor Arnold Schwarzenegger to CPUC President Michael Peevey.

10 California Pub. Util. Comm'n, *Administrative Law Judge's Ruling Requesting Additional Comments on Resource Adequacy Issues* (July 8, 2004).

11 *Id.*

12 California Pub. Util. Comm'n Decision 04-10-035 (October 28, 2004).

13 Approximately 19 workshops were held between November 2004 and April 2005. The CPUC staff issued its report on June 10, 2005 which can be found at *http://www.cpuc.ca.gov/PUBLISHED/REPORT/46914.PDF*. After comments and reply comments, Administrative Judge Wetzell issued an opinion on September 27, 2005.

Reserve Margin on a month-ahead basis; and (4) imposed an availability obligation of resources procured to meet the Resource Adequacy requirements.

The CPUC issued D.05-10-042 on October 27, 2005,[14] which affirmed and clarified the policy framework established in Decisions 04-01-050 and 04-10-035. The CPUC noted the following key determinations: (1) the adoption of a monthly system peak approach to defining the Resource Adequacy obligation; (2) adoption of deliverability tests and allocation of import capacity; (3) the recognition of the need for a localized capacity requirement but the postponement of its implementation to the 2007 procurement year so that it can be fully considered; and (4) the affirmation that sanctions for Load Serving Entity non-compliance with Resource Adequacy requirements are required.

The CPUC also concluded that an extension of the FERC must-offer obligation and associated waiver denial process should continue to be advocated as necessary for commitment of Resource Adequacy Resources until the implementation of CAISO's MRTU process.[15] The CPUC was concerned that if the must-offer obligation and associated waiver denial process are eliminated earlier, the CAISO will not have sufficient means to commit resources for the next day. The CPUC noted that, as with any major new program, unanticipated initial implementation issues are possible, and thus, it is prudent to proceed with caution.[16]

Proceeding number R05-12-013 was opened at the beginning of 2006 and will conduct workshops or otherwise address: (1) local capacity obligation, (2) multi-year procurement requirement, and (3) consideration of Capacity Markets.[17]

### C. CAISO Stakeholder Process

The stakeholder process regarding the MRTU Resource Adequacy requirements was extensive and covered many of the areas included in the Interim Reliability Requirements Program. The CAISO has sought to expand on the prior input and maintain meaningful stakeholder consultation into the Interim Reliability Requirements Program within the expedited timeframe in which this issue must be considered.

On February 3, 2006, the CAISO posted its proposed revisions to the ISO Tariff to incorporate the interim program. This draft was reviewed at a meeting with stakeholders on February 14, 2006. Following the meeting, 16 entities provided written

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14 California Pub. Util. Comm'n Decision 05-10-042 (October 27, 2005).

15 *Id.*

16 *Id.*

17 California Pub. Util. Comm'n, Docket No. R05-12-013.

comments on the proposals.[18] The CAISO considered the submissions and published a table summarizing its substantial revisions in response to the issues raised by stakeholders. The table served as a focus of a teleconference on March 2, 2006. The CAISO prepared revised tariff language, which was posted on March 8, 2008.

The CAISO presented the Interim Reliability Requirements Program to the Governing Board at the meeting on March 9, 2006. A copy of the package of materials proposed to the CAISO Board of Governors is attached as Attachment G hereto. The Board voted to authorize this filing.

### D. Independent Energy Producers Complaint

Concurrent with the implementation of the Interim Reliability Requirements Program, the CAISO is in the process of settlement negotiations with parties regarding a complaint filed by the Independent Energy Producers ("IEP") in Docket No. EL05-146-000 on the existing FERC must-offer obligation and a recommended replacement of the FERC must-offer obligation with a tariff-based Reliability Capacity Services Tariff ("RCST"). While the ultimate outcome of the IEP-RCST proceeding may impact the nature of the existing FERC must-offer obligation for resources not under supply contracts in accordance with the Resource Adequacy programs or Reliability Must Run contracts, the CAISO must proceed based on what is currently in effect. Given the tight implementation timetable, the CAISO must go forward with implementation of the Interim Reliability Requirements Program based on an assumption that the current form of the FERC must-offer obligation will exist within the construct for Resource Adequacy to be implemented by the CPUC and other Local Regulatory Authorities in accordance with AB 380. To the extent that the outcome of Docket No. EL05-146-000 dictates changes to the ISO's Tariff, those changes would be implemented in that proceeding. However, the CAISO emphasizes that the Interim Reliability Requirements Program as set forth herein can meet the CAISO's operational needs regardless of the outcome of the RCST proceeding and therefore is largely independent of any potential future tariff changes.

## IV. DESCRIPTION OF TARIFF CHANGES

The provisions of this ISO Tariff amendment are intended to support the implementation of the interim Resource Adequacy programs developed by the CPUC and other LRAs for Load Serving Entities under their respective jurisdiction. As noted in the memorandum to the CAISO Board of Governors, four interdependent, practical considerations guided the development of this amendment:

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18 Entities submitting comments included: Alliance for Retail Energy Markets, the Cogeneration Association of California and the Energy Producers and Users Coalition, the California Municipal Utilities Association, Northern California Power Agency, Pacific Gas & Electric Company, Powerex Corp., PPM Energy, Southern California Edison, Sempra Global, Sacramento Municipal Utility District, the Utility Reform Network, Western Area Power Administration, Williams Power Company, the City of Vernon, and the California Department of Water Resources State Water Project.

(1) while respecting the primary role of the CPUC and other LRAs, the CAISO remains statutorily obligated to operate the ISO Controlled Grid in accordance with Applicable Reliability Criteria and Good Utility Practice. To accomplish this requirement, the CAISO must have sufficient resources, in appropriate locations, to meet Demand. Moreover, the efforts of State regulatory entities to ensure that Load Serving Entities secure sufficient resources can only achieve the intended reliability benefits if the procurement rules are integrated with the design of the ISO Markets and bidding practices as well as the physical realities of the ISO Controlled Grid.

(2) the design features must be implementable on an expedited schedule to meet the CPUC's June 1, 2006 deadline.

(3) the design features would be temporary, intended only to be effective until implementation of MRTU in November 2007.

(4) while much work has been done, certain aspects of the California Resource Adequacy program are still evolving.

These four considerations led to the general principle that the Interim Reliability Requirements Program tariff provisions should be designed with an intent to minimize system changes at the CAISO, which requires reliance upon existing processes, procedures, and tariff authority to the maximum extent possible, while still looking ahead to the program under MRTU.

Thus, a primary change in the Interim Reliability Requirements Program is the manner in which the existing FERC must-offer obligation will transition to a backstop role. The CAISO proposes to revise the current "Must-Offer Waiver Denial Process" ("MOWD") to deny waivers *first* to those resources that have received a Resource Adequacy Capacity payment. In other words, the CAISO will, to the extent operationally practical, run the system without calling on units under the FERC must-offer obligation. Instead, the CAISO will issue a MOWD to Resource Adequacy Resources prior to issuing MOWD to non-Resource Adequacy Resources under the FERC must-offer obligation.[19]

The tariff has also been modified to reflect the understanding that a resource designated by a Load Serving Entity as a Resource Adequacy Resource should be compensated under the bilateral arrangement to make its capacity available to the CAISO. To implement this understanding, the CAISO proposes to revises the Minimum Load Cost Compensation ("MLCC") to recognize that Resource Adequacy Resources have received an explicit capacity payment and therefore no longer require the implicit capacity payment embodied in the current MLCC provisions.[20]

While utilizing Resource Adequacy Resources first, the Interim Reliability Requirements Program continues to rely for an interim period on the FERC must-offer obligation, the associated MOWD process and procedures, and the MLCC provisions to make resources available for commitment to meet CAISO reliability needs. When calling on resources under the FERC must-offer obligation, the CAISO does not

19 Resource operating constraints must be taken into consideration.

20 See *California Independent System Operator Corp.*, 111 FERC ¶ 61,207 at P 24 (2005).

propose to modify the existing scope of resources covered under the must-offer obligation or the cost compensation and cost allocation methodologies currently in place or subject to the outcome of ongoing proceedings (namely Amendment No. 60).

The proposed changes to Section 40 of the ISO Tariff are as follows:

### A. Applicability

The Interim Reliability Requirements Program applies the ISO Tariff's reliability requirements to all Scheduling Coordinators representing Load Serving Entities within the ISO Control Area. Load Serving Entities do not include customer generation located on the customer's site or providing service through arrangements authorized by Section 218 of the California Public Utilities Code under defined conditions. This is consistent with the provisions of A.B. 380. The jurisdictional status of each Load Serving Entity is accounted for in the ISO Tariff by deferring certain elements to the CPUC or the other relevant LRA, as described in more detail below.

The Resource Adequacy availability obligation can be viewed in three tiers. The first tier covers all resources listed in a Load Serving Entity's Resource Adequacy Plan and requires that the Load Serving Entity optimize the resource as it sees fit. The second tier applies to those listed resources that are under an affirmative offer obligation and included in the MOWD process. This tier would apply to those resources, other than hydro-electric, MSS resources, QF, and, if exempted by the CPUC or LRA, System Resources, listed in a Load Serving Entity's Resource Adequacy Plan. The third tier, also subject the MOWD process, includes that subset of Resource Adequacy Resources for which the CAISO will submit a proxy bid. This subset is the same as that under the current FERC must-offer obligation.

The Interim Reliability Requirements Program also keeps in place the FERC must-offer obligation that applies to all current FERC Must-Offer Generators as defined in the ISO Tariff. If a hydro-electric facility, a MSS System Unit, a System Resource, a QF, or any other entity is not subject to the FERC must-offer obligation today – it will continue to be exempt from such obligation under this amendment.

### B. Deference to the CPUC and Other Local Regulatory Authorities

The CAISO has acknowledged the primary role of the CPUC and LRAs in determining long-term procurement policies for Load Serving Entities under their jurisdiction. This deference is demonstrated in the proposed Section 40 by incorporating the following Resource Adequacy rules developed by the CPUC or other applicable LRAs:

- Demand forecast and protocols (Section 40.3)
- Planning Reserve Margin (Section 40.4), and
- Resource counting conventions (Section 40.5)

With respect to the Demand forecast and protocols, Planning Reserve Margin, and resource counting conventions, the CAISO proposes default criteria to be applied *only in the event that the Local Regulatory Authority does not establish its own criteria.* Moreover, the default criteria are based on the standards already adopted by the CPUC.

### C. Qualifying Capacity

Under the Interim Reliability Requirements Program, only Net Qualifying Capacity may be used to meet the Planning Reserve Margin and other elements of the program. Net Qualifying Capacity is the Qualifying Capacity as determined by the Local Regulatory Authority reduced, if necessary, by the CAISO's testing and verification and by deliverability restrictions described in Section D below. Again, what will constitute Qualifying Capacity will be determined, as appropriate, by the CPUC or, in the case of an entity not under the CPUC's jurisdiction, the applicable LRA. The default standard for Qualifying Capacity in Section 40.13 will apply only where a LRA has not determined what constitutes Qualifying Capacity.

### D. Deliverability

In order to effectively meet system needs, capacity must be deliverable. Deliverability generally means that the output of generating unit can reach load under peak conditions. The concept of deliverability under this amendment extends to generation inside the ISO Control Area to reach the aggregate of its load and the capability of imports for serving load inside the ISO Control Area.[21]

The CAISO will determine whether the capacity of a physical Generating Unit is available to serve the aggregate of Load by means of a deliverability analysis. The deliverability analysis will focus on peak Demand conditions. The CAISO will update the deliverability analysis on an annual basis. To the extent the deliverability analysis shows that the Qualifying Capacity of a Generating Unit or System Unit is not deliverable to the aggregate of Load under the conditions studied, the Qualifying Capacity of the resource will be reduced on a MW basis for the capacity that is undeliverable. The CAISO will utilize its Large Generator Interconnection Procedures and process so that future generator interconnections do not degrade the deliverability of existing resources.

With respect to Imports, the CAISO shall establish for 2006 for each branch group the total import capacity values to be allocated to Load Serving Entities serving Load in the ISO Control Area for Resource Adequacy planning purposes, and will update those values for 2007. Import capacity associated with Existing Rights and Encumbrances and Transmission Ownership Rights shall be reserved for holders of such commitments as part of the deliverability study and will not be subject to allocation.

[21] The CAISO previously posted overviews of its analysis for deliverability. It can be found on the CAISO Website at http://www.caiso.com/docs/2004/10/04/2004100410354511659.html.

The import capability of the system will be allocated to non-CPUC Load Serving Entities individually and to the CPUC Load Serving Entities as an aggregated allocation, which will be subject to the allocation rules of the CPUC.

For 2006, the allocation will be as follows:

- Non-CPUC Load Serving Entities will receive an allocation on a particular branch group equal to each entity's resource commitments outside the ISO Control Area, as of October 27, 2005 that utilizes the particular branch group through calendar year 2006.

- CPUC Load Serving Entities will receive an aggregate import value by branch group that is equal to the maximum value for each branch group minus import capacity associated with (i) Existing Transmission Contracts, (ii) Encumbrances and Transmission Ownership Rights, and (iii) resource commitments outside the ISO Control Area of non-CPUC Load Serving Entities, as of October 27, 2005

Similar rules will apply for 2007 except the cut off date shall be March 10, 2006 instead of October 2005. The CAISO selected the March 10th date for several reasons. Most significantly this approach provides certainty in procurement. As such, all existing commitments of non-CPUC jurisdictional entities will be respected and allocated first. Given that the CPUC entities will get the remainder, the CAISO believes the selection of the March 10, 2006 date strikes an appropriate balance between the two categories of Load Serving Entities. The CPUC entities need to know their allocation values with sufficient lead-time that they may engage in new contracts for the 2007 period. Moreover, the CAISO must receive the contracts data from the non-CPUC jurisdictional entities, conduct an analysis, and determine the remaining available capacity. The CAISO will need a few weeks to perform these activities. The CPUC-jurisdictional entities have consistently requested at least 90 days to conduct their procurement activities before they must make the next required reporting. The significant reporting period is the year ahead report that is due September 30, 2006 for the summer months of 2007.

This process responds to stakeholder concerns for certainty by allocating intertie capacity on a forward basis so as to encourage contracting. In this regard, certain stakeholders noted the importance of being able to make long-term procurement decisions with respect to resources outside the ISO Control Area with the assurance that these resources would be deliverable and count toward fulfillment of a Resource Adequacy obligation. The CAISO understands and agrees that security of long-term supply arrangements is critical. Nevertheless, this amendment is a temporary, transitional program. The issue of a long-term allocation of import capacity for Resource Adequacy purposes should be addressed on a comprehensive basis with the other elements of the MRTU market design.

This allocation does not guarantee or result in any actual transmission service being allocated and is only used for determining the maximum Resource Adequacy Capacity that can be credited towards satisfying a Scheduling Coordinator's Resource Adequacy obligation. Upon the request of the CAISO, Scheduling Coordinators must provide the CAISO with information on existing import contracts and any trades or sales of their load share allocation. Such information will be subject to the confidentiality provisions of the ISO Tariff. The CAISO will inform the CPUC or other Local Regulatory Authority of Resource Adequacy Plan submitted by a Scheduling Coordinator for a Load Serving Entity under their respective jurisdiction that exceeds its allocation of import capacity.

## E. Reporting Requirements

### 1. Reports from Scheduling Coordinators Representing Load Serving Entities

The Interim Reliability Requirements Program contains several reporting requirements that will enable the CAISO to ensure overall adequacy of resources by verifying the Resource Adequacy program of each Load Serving Entity. Scheduling Coordinators for Load Serving Entities are required to submit annual and monthly Resource Adequacy Plans.

The annual and monthly Resource Adequacy Plan provided to the CAISO by Scheduling Coordinators for the CPUC Load Serving Entities are to be submitted on the schedule and in the form approved by the CPUC. The annual and monthly Resource Adequacy Plans provided to the CAISO by Scheduling Coordinators for the non-CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area are to be submitted on the dates set forth in the tariff and in the form set forth on the CAISO website. To minimize the difficulty imposed on the CAISO personnel and process for integrating the information in the Resource Adequacy Plans, other than for good cause, the form of the Resource Adequacy Plan and the date for submission for the CPUC Load Serving Entities and the Non-CPUC Load Serving Entities is to be identical.

The annual and monthly Resource Adequacy Plan must identify the Resource Adequacy Resources that will be relied upon to satisfy the Planning Reserve Margin and must apply the Net Qualifying Capacity requirements. If a Scheduling Coordinator for a Load Serving Entity submits a Resource Adequacy Plan that the CAISO identifies as not demonstrating compliance with Resource Adequacy rules adopted by the CPUC or other LRA, the CAISO will first notify the relevant Scheduling Coordinator, or in the case of a mismatch between a Resource Adequacy Plan and a Supply Plan, the relevant Scheduling Coordinators, and attempt to resolve the issue. If this process does not resolve the CAISO's concern, the CAISO will notify the CPUC or other appropriate LRA of the potential deficiency. To the extent that the CPUC or other appropriate LRA allows Load Serving Entities under its jurisdiction to cure the identified deficiency or determines that no deficiency exists, the Scheduling Coordinator(s) are to inform the

CAISO at least 10 days before the effective month of the outcome of any resolution. If the deficiency is not resolved, the CAISO will use the information contained in the Supply Plan to set Resource Adequacy Resources' obligations.

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

2. Reports by Suppliers

In addition to the showing of reports from Load Serving Entities, the CAISO would require Scheduling Coordinators for all Generating Units, System Units, and System Resources that have capacity committed through Resource Adequacy contracts to submit Annual and Monthly Supply Plans to the CAISO confirming the existence of a contractual agreement to provide such capacity.

These Supply Plans would show the amount of Resource Adequacy Capacity sold per unit to each Load Serving Entity and the total quantity of Resource Adequacy Capacity for each resource listed in the report. The form of the Supply Plan would be posted on the CAISO website.

**F. Availability**

The CAISO proposes to build from the existing processes and procedures that support the FERC must-offer policy, including the MOWD process. In this regard, the CAISO intends to use the MOWD process to make commitment decisions for Resource Adequacy Resources that have long-start times that have otherwise not scheduled energy or ancillary services in the Day-Ahead Market. The CAISO shall make MOWD decisions such that Resource Adequacy Resources are utilized to the extent possible, considering transmission constraints, prior to dispatching a non-contracted resource that is otherwise still subject to the FERC must-offer obligation.

**G. Must-Offer Obligation Overview and Waiver Process**

The Interim Reliability Requirements Program contains a three-prong offer obligation described in Section IV.A above. By virtue of its inclusion in the Resource Adequacy Plan of a Load Serving Entity and its Supply Plan, a generator becomes subject to the Resource Adequacy Capacity availability obligation under section 40.6A.4 of the Tariff. In addition, the amendment keeps in place the existing FERC must-offer obligation applied to all current FERC Must-Offer Generators. The CAISO's unit commitment process will create a priority order that, if necessary, first denies the waiver requests of Resource Adequacy Resources and then, only if necessary, denies FERC must-offer obligation waiver requests. Capacity will be committed under revised Section 40 in the following priority order:

1. Generators committed through a balanced schedule;

2. If unscheduled and there is need for capacity, the CAISO will deny Resource Adequacy Resources waiver requests;

3. If Resource Adequacy Capacity is insufficient, the CAISO will deny FERC must-offer obligation waiver requests; and

4. Uncommitted Resource Adequacy Capacity and FERC must-offer obligation capacity should be offered in real-time as Supplemental Energy, or CAISO will a create proxy bid. A Resource Adequacy Resource that is physically capable and is not otherwise explicitly exempted from making its Resource Adequacy Capacity available in the Real-Time Market or has a MOWD accepted, must offer supplemental bids in the Real-Time Market.

Thus, the primary difference between the current FERC must-offer obligation and the Resource Adequacy Capacity obligation is that the priority resources will be subject to denials of must-offer waivers.

### H. Settlement of Must-Offer Minimum Load Costs

Under the current MLCC design, Scheduling Coordinators representing generating resources that are operating in compliance with the FERC must-offer obligation, and pursuant to a MOWD, receive an Instructed Imbalance Energy payment for each Settlement Interval within the relevant hour. Additionally, Scheduling Coordinators receive an MLCC payment based on generating unit heat-rate, fuel costs, and compensation for "operations and maintenance" at $6.00/MWh. Generators that have not entered into Resource Adequacy agreements and are not counted toward meeting Load Serving Entities Qualifying Capacity obligation will continue to be subject to the FERC must-offer obligation compensation system. The MLCC for non-Resource Adequacy Generators operating in compliance with the FERC must-offer obligation will remain unchanged.

In the proposed tariff changes, the CAISO guarantees MLCC recovery for Resource Adequacy Resources for each Settlement Interval during hours within a Waiver Denial Period. The minimum load Energy would be accounted as Instructed Imbalance Energy and would be settled at the Resource-Specific Settlement Interval Ex Post Price. To the extent the Instructed Imbalance Energy payments are not sufficient to cover the generator's Minimum Load Cost, the generator will receive an uplift payment to ensure that it receives full MLCC compensation. If the generator is dispatched for real time Imbalance Energy above its minimum load during the Waiver Denial Period, the generator will be eligible for bid cost recovery. Resource Adequacy

Un-Recovered Minimum Load Costs will be allocated the same as MLCC for FERC Must-Offer Generators denied waivers under the FERC must-offer obligation. The unrecovered portion of MLCC will be allocated consistent with the methodology for allocating MLCC under the FERC must-offer obligation.

Recovery of start-up and emissions costs for both Resource Adequacy Resources and FERC Must-Offer Generators would be based on the existing cost compensation methodologies for these charges.

### I. Enforcement

As noted above, the CAISO would report any deficiencies, such as lack of Resource Adequacy Capacity or inaccuracies in Resource Adequacy Plans from CPUC jurisdictional entities to the CPUC for enforcement. Similarly, the CAISO would report deficiencies to the applicable LRA for non-CPUC jurisdictional entities. Other measures to ensure compliance with the Resource Adequacy requirements would include enforcement of the market rules specified in the ISO Tariff Enforcement Protocol (Section 37 of the ISO Tariff), or referrals to FERC as a potential violation of its market rules. Scheduling Coordinators would be subject to penalties of $500 for each day a report is late as pursuant to Section 37.6. In addition, all plans submitted as part of the Resource Adequacy program are subject to market rules regarding the factual accuracy of information, including Sections 37.5 and 37.7, and FERC's market rules. A Resource Adequacy Generating Unit or System Unit that fails to comply with its must-offer obligation would be subject to a penalty pursuant to Section 37.2.4.

### J. Defined Terms

In order to implement the proposed Interim Reliability Requirements Program, the CAISO proposes to add a number of defined terms to the Master Definition Supplement in Appendix A of the ISO Tariff including: FERC Must-Offer Generator, Load Serving Entity, Net Qualifying Capacity, Planning Reserve Margin, Qualifying Capacity, Resource Adequacy, Resource Adequacy Capacity, Resource Adequacy Plan, Resource Adequacy Resource, Short Start, Supply Plan, Transmission Ownership Rights, and Un-Recovered Minimum Load Cost.

## V. EFFECTIVE DATE AND PART 35 COMPLIANCE

The CAISO respectfully requests that the revised tariff sheets attached hereto be approved, without modification, suspension, or hearing, to go into effect on May 31, 2006, with the exception of Sections 40.2 (and subsections thereof) and 40.6 (and subsections thereof) regarding the annual and monthly Resource Adequacy Plan and Supply Plan reporting obligations, for which the CAISO requests an effective date of May 12, 2006, 60 days from this filing. Earlier acceptance of the reporting obligations will allow Market Participants and the CAISO to orderly transfer from the existing regime based on the FERC must-offer obligation to the Interim Reliability Requirements Program, implementing the Resource Adequacy requirements imposed by the CPUC and other Local Regulatory Authorities. By receiving the annual and monthly Resource Adequacy Plans and Supply Plans, the CAISO can better ensure that adequate resources will be available to meet system requirements when the remainder of the interim program goes into effect on May 31, 2006, coincident with the CPUC requirements.

The attached ISO Tariff sheets are provided in a clean version and a version redlined against the CAISO's Simplified and Reorganized Tariff ("S & R Tariff") that was recently approved by the Commission to be effective March 1, 2006.[22]

## VI. SUPPORTING DOCUMENTS

This transmittal letter is intended to provide the Commission with an overview of the proposed revisions to the ISO Tariff. The attached tariff sheets contain each of the proposed ISO Tariff changes.

The supporting documents submitted with this filing are as follows:

| | |
|---|---|
| Attachment A | Clean Section 40 ISO Tariff Sheets |
| Attachment B | Section 40 ISO Tariff Redlined Against the CAISO S&R Tariff |
| Attachment C | Clean ISO Tariff and Appendix Sheets Reflecting New or Amended Definitions and Cross References |
| Attachment D | ISO Tariff and Appendix Reflecting New or Amended Definitions and Cross References Redlined Against the ISO S&R Tariff |
| Attachment E | Clean ISO Tariff Index |
| Attachment F | ISO Tariff Index Redlined Against the ISO S&R Tariff |
| Attachment G | Package of Materials Submitted to the CAISO Board of Governors and Resolution of CAISO Board of Governors Authorizing the Instant Filing |

22 The S & R Tariff reflects all tariff amendments and corrections accepted by the Commission as of August 31, 2005, with language that was pending as of that date shaded in gray.

## VI. SERVICE

The CAISO has served copies of this filing on the Public Utilities Commission of the State of California, the California Energy Commission, the California Electricity Oversight Board, and all parties with Scheduling Coordinator Agreements under the CAISO Tariff. In addition, the CAISO has posted a copy of the filing on the CAISO Website and will provide courtesy copies of this filing to all parties in the MRTU proceeding, FERC Docket No. ER02-1656-000.

## VII. 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:[23]


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23 The CAISO respectfully requests waiver of Rule 203(b)(3), 18 C.F.R. § 385.203(b)(3), to permit each of the persons listed above to be included on the service list for this proceeding.

## VIII. CONCLUSION

Wherefore, for all the reasons stated above, the CAISO respectfully requests that revised tariff sheets included in this filing be approved, without modification, suspension, or hearing to go into effect on May 12, 2006 or May 31, 2006 as requested herein.

Respectfully Submitted,

/s/ ______________________________
Grant Rosenblum
Counsel for the
California Independent System Operator
Corporation

# ATTACHMENT A

implementation and effect of such measure on the state of the ISO Markets and shall periodically report on them to the CEO and the ISO Governing Board.

**39 RULES LIMITING CERTAIN ENERGY AND ANCILLARY SERVICE BIDS.**

**39.1 Damage Control Bid Cap.**

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

**39.2 Maximum Bid Level.**

The maximum bid level shall be $250/MWh. Market Participants may submit bids above $250/MWh, however, any accepted bids above this cap are not eligible to set the Market Clearing Price and are subject to cost-justification and refund.

**39.3 Negative Decremental Energy Bids.**

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

**ARTICLE V – RESOURCE ADEQUACY**

**40 RESOURCE ADEQUACY.**

**40.1 Applicability.**

This Section 40 applies to all Scheduling Coordinators representing Load Serving Entities serving retail Load within the ISO Control Area. For purposes of this Section 40 of the ISO Tariff, Load Serving Entity is defined as: (1) any entity serving retail Load under the jurisdiction of the California Public Utilities Commission (hereinafter "CPUC"), including an Electrical corporation under section 218 of the California Public Utilities Code (hereinafter "PUC"), an Electric service provider under section 218.3 of the PUC, and a Community choice aggregator under section 331.1 of the PUC (hereinafter collectively "CPUC Load Serving Entities"); and (2) all entities serving retail Load in the ISO Control Area not within the jurisdiction of the CPUC including: (i) a local publicly owned electric utility under section 9604 of the PUC; (ii) the State Water Resources Development System commonly known as the State Water Project; and (iii) any Federal entities, including but not limited to Federal Power Marketing Authorities, that serve retail Load (hereafter collectively "non-CPUC Load Serving Entities"). Load Serving Entity shall not include customer generation located on the customer's site or providing electric service through arrangements authorized by Section 218 of the PUC, if the customer generation, or the Load it serves, meets one of the following criteria: (i) it takes standby service from the electrical corporation on a commission-approved rate schedule that provides for adequate backup planning and operating reserves for the standby customer class; (ii) it is not physically interconnected to the electric transmission or distribution grid, so that if the customer generation fails, backup electricity is not supplied from the electricity grid; or (iii) there is physical assurance that the Load served by the customer generation will be curtailed concurrently and commensurately with an outage of the customer generation.

**40.2 Submission of Annual and Monthly Resource Adequacy Plan.**

**40.2.1 Annual Resource Adequacy Plan.**

Each Scheduling Coordinator for a Load Serving Entity serving Load within the ISO Control Area must provide the ISO with an annual Resource Adequacy Plan. The annual Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area shall be submitted on the schedule and in the form approved by the CPUC. The annual Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the non-CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area shall be submitted no later than September 30th of each year and in the form set forth on the ISO Website. Other than for good cause, the form of the Resource Adequacy Plan and the date for submission for the CPUC Load Serving Entities and the Non-CPUC Load Serving Entities should be identical. The annual Resource Adequacy Plan must identify the Resource Adequacy Resources that will be relied upon to satisfy the Planning Reserve Margin under Section 40.4, or portion thereof as established by the CPUC or applicable Local Regulatory Authority, and must apply the Net Qualifying Capacity requirements of Section 40.5.2.

**40.2.2 Monthly Resource Adequacy Plan.**

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

**40.2.3 Resource Adequacy Plan Compliance.**

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

**40.2.4 Reporting of Enforcement Actions.**

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

**40.2.5 Compliance with Submission Obligation.**

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

**40.3 Demand Forecasts.**

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

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

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

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

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

**40.4 Planning Reserve Margin.**

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

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

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

c. For Scheduling Coordinators representing Load Serving Entities for which the CPUC or other Local Regulatory Authority has not established a Planning Reserve Margin, the Planning Reserve Margin shall be no less than 115% of the peak hour of the month in the Demand Forecast set forth in Section 40.3.

**40.5 Determination of Resource Adequacy Capacity.**

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

**40.5.1 Qualifying Capacity.**

Qualifying Capacity is the capacity from a resource prior to application of the Net Capacity provisions of Section 40.5.2. The criteria for determining the types of resources that may be eligible to provide Qualifying Capacity and for calculating Qualifying Capacity from eligible resource types may be established by the CPUC or other applicable Local Regulatory Authority and provided to the ISO. Only if such criteria are not provided by the CPUC or other Local Regulatory Authority, Section 40.13 will apply. The ISO shall use the criteria provided by the CPUC, other Local Regulatory Authority or, if necessary, Section 40.13, to determine and verify, if necessary, the Qualifying Capacity of all resources listed in a Resource Adequacy Plan; however, to the extent a resource is listed by one or more Scheduling Coordinators in their respective Resource Adequacy Plans, which apply the criteria of more than one regulatory entity that leads to conflicting Qualifying Capacity values for that resource, the ISO will apply the respective Qualifying Capacity formulas applicable for each Load Serving Entity.

**40.5.2 Net Qualifying Capacity.**

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

**40.5.2.1 Deliverability Within the ISO Control Area.**

In order to determine Net Qualifying Capacity from a Generating Unit, the ISO will determine that the Generating Unit is able to serve the aggregate of Load by means of a deliverability analysis. The deliverability analysis shall focus on peak Demand conditions. The ISO will review its input assumptions and draft results with Market Participants before completing its determination. The ISO will update the deliverability baseline analysis on an annual basis. The ISO will coordinate with the CPUC and other Local Regulatory Authorities so that the deliverability analysis can be utilized in the development of Resource Adequacy Plans. To the extent the deliverability analysis shows that the Qualifying Capacity of a Generating Unit is not deliverable to the aggregate of Load under the conditions studied, the Qualifying Capacity of the Generating Unit will be reduced on a MW basis for the capacity that is undeliverable. The ISO will utilize its interconnection process and procedures under Section 25 of the ISO Tariff to prevent degradation of the deliverability of an existing Generating Unit that could result from the interconnection of additional Generation.

**40.5.2.2 Deliverability of Imports.**

This Section 40.5.2.2 shall apply only to Resource Adequacy Plans covering the period through December 31, 2007, unless superseded earlier by alternative ISO Tariff provisions. The ISO shall establish for 2006 for each branch group the total import capacity values to be allocated to Load Serving Entities serving Load in the ISO Control Area for Resource Adequacy planning purposes, and will update those values for 2007. The updated import capacity values shall be posted on the ISO Website. Import capacity associated with (i) Existing Transmission Contracts and (ii) Encumbrances and Transmission Ownership Rights shall be reserved for holders of such commitments as part of the deliverability study and will not be subject to allocation under this Section. For the purpose of accounting for import Resource Adequacy Capacity, the import capability of the system will be allocated by branch group by the ISO (1) to non-CPUC Load Serving Entities individually and (2) to the CPUC Load Serving Entities as an aggregated allocation, which will be subject to the allocation rules of the CPUC.

For 2006, the allocation will be as follows:

a. Non-CPUC Load Serving Entities will receive an allocation on a particular branch group equal to each entity's resource commitments outside the ISO Control Area, as of October 27, 2005 that utilizes the particular branch group through calendar year 2006.

b. CPUC Load Serving Entities will receive an aggregate import value by branch group that is equal to the maximum value for each branch group minus import capacity associated with (i) Existing Transmission Contracts, (ii) Encumbrances and Transmission Ownership Rights, and (iii) resource commitments outside the ISO Control Area of non-CPUC Load Serving Entities, as of October 27, 2005 as provided for in Section 40.5.2.2(a).

For 2007, the allocation will be as follows:

c. Non-CPUC Load Serving Entities will receive an allocation on a particular branch group equal to each entity's resource commitments outside the ISO Control Area, as of March 10, 2006 that utilizes the particular branch group through calendar year 2007.

d. CPUC Load Serving Entities will receive an aggregate import value by branch group that is equal to the maximum value for each branch group minus import capacity associated with (i) Existing Transmission Contracts, (ii) Encumbrances and Transmission Ownership Rights, and (iii) resource commitments outside the ISO Control Area of non-CPUC Load Serving Entities, as of March 10, 2006 as provided for in Section 40.5.2.2(c).

This allocation does not guarantee or result in any actual transmission service being allocated and is only used for determining the maximum Resource Adequacy Capacity that can be credited towards satisfying a Scheduling Coordinator's Resource Adequacy obligation. Upon the request of the ISO, Scheduling Coordinators must provide the ISO with information on existing import contracts and any trades or sales of their load share allocation. Such information will be subject to the confidentiality provisions of this ISO Tariff. The ISO will inform the CPUC or other Local Regulatory Authority of Resource Adequacy Plan submitted by a Scheduling Coordinator for a Load Serving Entity under their respective jurisdiction that exceeds its allocation of import capacity.

**40.6 Submission of Supply Plans.**

Scheduling Coordinators representing Resource Adequacy Resources supplying Resource Adequacy Capacity shall provide the ISO with annual and monthly Supply Plans. The annual Supply Plan shall be provided by September 30th of each year. The monthly Supply Plan shall be provided on the last business day of the second month prior to the compliance month (e.g., March 31 for May). Both the annual and monthly Supply Plans shall be provided in the form set forth on the ISO's Website, listing their commitments to provide Resource Adequacy Capacity to any Load Serving Entity or Entities for the reporting period. Such plans will be accorded protection in accordance with the confidentiality provisions of this ISO Tariff.

**40.6.1 Compliance with Supply Plan Obligation.**

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

**40.6A Availability of Resource Adequacy Resources.**

**40.6A.1 Applicability.**

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

**40.6A.2 Available Generation.**

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

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

So that the ISO may determine the Available Generation of Resource Adequacy Resources, Resource Adequacy Resources that are not Participating Generators shall be required to file with the ISO: (i) the Generating Unit's minimum operating level; (ii) the Generating Unit's maximum operating level; and (iii) the Generating Unit's ramp rates at all operating levels; and (iv) such other information the ISO determines is necessary to determine available generation and to dispatch Resource Adequacy

Resources. In addition, Resource Adequacy Resources that are not Participating Generators must, consistent with the notification obligations of Participating Generators and in order to comply with the intent of this Section 40.6A, notify the ISO, as soon as practicable, of any Planned Maintenance Outages, Forced Outages, Force Majeure Event outages or any other reductions in their maximum operating levels or Resource Adequacy Capacity during the relevant month.

**40.6A.4 Obligation to Offer Available Capacity.**

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

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

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

If a Resource Adequacy Resource fails to submit a Supplemental Energy bid for any portion of its Available Generation for any Dispatch Interval, the un-bid quantity of the Resource Adequacy Resource's Available Generation will be deemed by the ISO to be bid at the Resource Adequacy Resource's Proxy Price if (i) the Resource Adequacy Resource is a gas-fired Generating Unit and (ii) the Resource Adequacy Resource has provided the ISO with adequate data in compliance with Section 40.6A.3 for the applicable Generating Unit. For all other Resource Adequacy Resources that are Generating Units, the un-bid quantity of the Resource Adequacy Resources' Available Generation will be deemed by the ISO to be bid and settled in accordance with Section 11.2. In order to dispatch resources providing Imbalance

Energy in proper merit order the ISO will insert this un-bid quantity into the Resource Adequacy Resource's Supplemental Energy bid curve above any lower-priced segments of the bid curve and below any higher-priced segments of the bid curve as necessary to maintain a non-decreasing bid curve over the entire range of the Resource Adequacy Resources' Available Generation.

**40.6A.6 Resource Adequacy Resource Obligation Process.**

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

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

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

**40.6A.7 Penalties for Non-Compliance.**

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

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

**40.6B.1 Eligibility.**

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

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

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

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

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

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

**40.6B.4 Un-Recovered Minimum Load Costs.**

The Un-Recovered Minimum Load Costs for each hour of Waiver Denial Period shall be calculated as the difference between: (1) a resource's Minimum Load Costs as calculated in this Section for the same Settlement Interval and (2) the Imbalance Energy payment for a resource's minimum load energy in the Settlement Interval. If the Imbalance Energy payment for minimum load energy exceeds the Minimum Load Costs, then there are no Un-Recovered Minimum Load Costs. The Minimum Load Costs shall be calculated as the sum, for all eligible hours in the Waiver Denial Period and Settlement Periods in which the unit generated in response to an ISO Dispatch Instruction, of: (1) the product of the unit's average heat rate (as determined by the ISO from the data provided in accordance with Section 40.10) at the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC and the gas price determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Resource Adequacy Resource is not served from one of those three Service Areas; and (2) the product of the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC; and $6.00/MWh.

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

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

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

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

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

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

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

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

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

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

**40.7 FERC Must-Offer Obligations.**

**40.7.1 Applicability.**

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

**40.7.2 Available Generation.**

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

**40.7.3 Reporting Requirements for Non-Participating Generators.**

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

**40.7.4 Obligation To Offer Available Generation.**

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

**40.7.5 Submission of Bids and Applicability of the Proxy Price.**

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

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

**40.7.6 FERC Must-Offer Obligation Process.**

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

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

Ahead Energy Schedules will be deemed to have requested a waiver, either implicitly or explicitly, of the obligation to offer all Available Generation. If conditions permit, the ISO may, at its sole discretion, grant waivers and allow a FERC Must-Offer Generator to remove one or more Generating Units or System Units from service. In doing so, the ISO will first grant waivers to FERC Must-Offer Generators, on a non-discriminatory basis, that are not also Resource Adequacy Resources and then, if permissible, the ISO may grant waivers to Resource Adequacy Resources on a non-discriminatory basis.

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

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

**40.8.1 Eligibility.**

Except as set forth below, Generating Units shall be eligible to recover Minimum Load Costs during Waiver Denial Periods. Units from FERC Must-Offer Generators that incur Minimum Load Costs during hours for which the ISO has granted to them a waiver shall not be eligible to recover such costs for such hours. When a FERC Must-Offer Generator has a Final Hour-Ahead Energy Schedule, the FERC Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. When, on a 10-minute Settlement Interval basis, a FERC Must-Offer Generator generating at minimum operating level in compliance with the must-offer obligation, produces a quantity of Energy that varies from its minimum operating level by more than the Tolerance Band, the FERC Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such Settlement Intervals during hours within a Waiver Denial Period. When, on a Settlement Interval basis, a FERC Must-Offer Generator's resource produces a quantity of Energy above minimum load due to an ISO Dispatch Instruction, the FERC Must-Offer Generator shall recover its Minimum Load Costs as set forth in this Section and its bid costs, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band. Subject to the foregoing eligibility restrictions set forth in this section, the ISO shall guarantee recovery of the Minimum Load Costs of an otherwise eligible FERC Must-Offer Generator for each Settlement Interval during hours within a Waiver Denial Period as follows: (1) First, ISO will pre-dispatch for real time the minimum load Energy from FERC Must-Offer Generators that have been denied waivers for each hour within a Waiver Denial Period; (2) This minimum load Energy will be accounted as Instructed Imbalance Energy for each Settlement Interval within the relevant hour and be settled at the Resource-Specific Settlement Interval Ex Post Price; (3) The generator's Minimum Load Cost as defined in Section 40.8.4 of this ISO Tariff, the generator will also receive a payment for its Minimum Load Cost compensation for the relevant eligible Settlement Intervals of hours during the Waiver Denial Period that the Generating Unit runs at minimum load in compliance with the must-offer obligation; and (4) To the extent the Generator is dispatched for real time Imbalance Energy above its minimum load for any Dispatch Interval within an hour during the Waiver Denial Period, the Generator will be eligible for Bid Cost Recovery, as set forth in Section 11.2.4.1.1.1.

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

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

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

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

**40.8.4 Minimum Load Costs.**

The Minimum Load Costs shall be calculated as the sum, for all eligible hours in the Waiver Denial Period and Settlement Periods in which the unit generated in response to an ISO Dispatch Instruction, of: (1) the product of the unit's average heat rate (as determined by the ISO from the data provided in accordance with Section 40.10) at the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC and the gas price determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the FERC Must-Offer Generator is not served from one of those three Service Areas; and (2) the product of the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC; and $6.00/MWh.

**40.8.5 [Not Used]**

**40.8.6 Allocation of Minimum Load Costs.**

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

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

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

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

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

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

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

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

**40.9 Criteria for Issuing Must-Offer Waivers.**

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

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

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

**40.10.1 Calculation of the Proxy Price.**

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

**40.11 Emissions Costs.**

**40.11.1 Obligation to Pay Emissions Cost Charges.**

Each Scheduling Coordinator shall be obligated to pay a charge which will be used to pay the verified Emissions Costs incurred by a Resource Adequacy Resource or FERC Must-Offer Generator as a direct result of an ISO Dispatch Instruction, in accordance with this Section 40. The ISO shall levy this administrative charge (the "Emissions Cost Charge") each month, against all Scheduling Coordinators based upon each Scheduling Coordinator's Control Area Gross Load and Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area. Scheduling Coordinators shall make payment for all Emissions Cost Charges in accordance with the ISO Payments Calendar.

**40.11.2 Emissions Cost Trust Account.**

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

**40.11.3 Rate For the Emissions Cost Charge.**

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

**40.11.4 Adjustment of the Rate For the Emissions Cost Charge.**

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

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

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

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

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

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

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

**40.11.6 Submission of Emissions Cost Invoices.**

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

**40.11.7 Payment of Emissions Cost Invoices.**

The ISO shall pay Scheduling Coordinators for all Emissions Costs submitted in an Emissions Cost Invoice and demonstrated to be a direct result of an ISO Dispatch Instruction. If the Emissions Costs indicated in the applicable air quality districts' final invoice statements include emissions produced by operation not resulting from ISO Dispatch Instructions, the ISO shall pay an amount equal to Emissions Costs multiplied by the ratio of the MWh associated with ISO Dispatch Instruction to the total MWh associated with such Emissions Costs. The ISO shall pay Emissions Cost Invoices each month in accordance with the ISO Payments Calendar from the funds available in the Emissions Cost Trust Account. To the extent there are insufficient funds available in Emissions Cost Trust Account in any month to pay all Emissions Costs submitted in an Emissions Cost Invoice and demonstrated to be a direct result of an ISO Dispatch Instruction, the ISO shall make pro rata payment of such Emissions Costs and shall adjust the rate at which the ISO will assess the Emissions Cost Charge in accordance with Section 40.11.4. Any outstanding Emissions Costs owed from previous months will be paid in the order of the month in which such costs were invoiced to the ISO. The ISO's obligation to pay Emissions Costs is limited to the obligation to pay Emissions Cost Charges received. All disputes concerning payment of Emissions Cost Invoices shall be subject to ISO ADR Procedures, in accordance with Section 13 of this ISO Tariff.

**40.12 Start-Up Costs.**

**40.12.1 Obligation to Pay Start-Up Cost Charges.**

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

**40.12.2 Start-Up Cost Trust Account.**

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

**40.12.3 Rate For the Start-Up Cost Charge.**

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

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

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

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

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

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

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

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

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

**40.12.6 Submission of Start-Up Cost Invoices.**

Scheduling Coordinators for Resource Adequacy Resources or FERC Must-Offer Generators that incur Start-Up Costs as a direct result of an ISO Dispatch Instruction or if the ISO revokes a waiver from compliance with the FERC must-offer obligation while the unit is off-line in accordance with Section 40.6A.6 or 40.7.6 of this ISO Tariff, and Scheduling Coordinators for Generating Units or System Units operating under Condition 2 of the relevant RMR Contract which are called out-of-market in accordance with Section 11.2.4.2 of this ISO Tariff may submit to the ISO an invoice in the form specified on the ISO Website (the "Start-Up Cost Invoice") for the recovery of such Start-Up Costs. Such Start-Up Costs shall not exceed the costs which would be incurred within the start-up time for a unit specified in Schedule 1 of the Participating Generator Agreement. Start-Up Cost Invoices shall use the applicable proxy figure for natural gas costs as determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Resource Adequacy Resource or FERC Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas. Start-Up Cost Invoices shall specify the amount of auxiliary power used during the start-up and the actual price paid for that power. Start-Up Cost Invoices shall not include any Start-Up Costs specified in an RMR Contract for a unit owned or controlled by a FERC Must-Offer Generator.

**40.12.7 Payment of Start-Up Cost Invoices.**

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

Start-Up Costs is limited to the obligation to pay Start-Up Cost Charges received. All disputes concerning payment of Start-Up Cost Invoices shall be subject to ISO ADR Procedures, in accordance with Section 13 of this ISO Tariff.

**40.13 ISO Default Qualifying Capacity Criteria.**

**40.13.1 Applicability.**

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

**40.13.2 Nuclear and Thermal.**

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

**40.13.3 Hydro.**

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

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

**40.13.4 Unit-Specific Contracts.**

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

**40.13.5 Contracts with Liquidated Damage Provisions.**

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

**40.13.6 Wind and Solar.**

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

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

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

**40.13.7 Geothermal.**

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

**40.13.8 Treatment of Qualifying Capacity for QFs.**

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

**40.13.9 Participating Load Resources.**

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

**40.13.10 Jointly-Owned Facilities.**

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

**40.13.11 Facilities Under Construction.**

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

**40.13.12 System Resources.**

**40.13.12.1 Dynamically Scheduled System Resources.**

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

**40.13.12.2 Non-Dynamically Scheduled System Resources.**

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

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

**41 Procurement of RMR.**

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

**42.1 Generation Planning Reserve Criteria.**

Generation planning reserve criteria shall be met as follows:

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

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

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

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

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

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

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

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

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

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

Replacement Reserve in that hour.

# ATTACHMENT B

**ARTICLE V – RESOURCE ADEQUACY**

## 40 RESOURCE ADEQUACY.

### 40.1 Applicability.

This Section 40 applies to all Scheduling Coordinators representing Load Serving Entities serving retail Load within the ISO Control Area. For purposes of this Section 40 of the ISO Tariff, Load Serving Entity is defined as: (1) any entity serving retail Load under the jurisdiction of the California Public Utilities Commission (hereinafter "CPUC"), including an Electrical corporation under section 218 of the California Public Utilities Code (hereinafter "PUC"), an Electric service provider under section 218.3 of the PUC, and a Community choice aggregator under section 331.1 of the PUC (hereinafter collectively "CPUC Load Serving Entities"); and (2) all entities serving retail Load in the ISO Control Area not within the jurisdiction of the CPUC including: (i) a local publicly owned electric utility under section 9604 of the PUC; (ii) the State Water Resources Development System commonly known as the State Water Project; and (iii) any Federal entities, including but not limited to Federal Power Marketing Authorities, that serve retail Load (hereafter collectively "non-CPUC Load Serving Entities"). Load Serving Entity shall not include customer generation located on the customer's site or providing electric service through arrangements authorized by Section 218 of the PUC, if the customer generation, or the Load it serves, meets one of the following criteria: (i) it takes standby service from the electrical corporation on a commission-approved rate schedule that provides for adequate backup planning and operating reserves for the standby customer class; (ii) it is not physically interconnected to the electric transmission or distribution grid, so that if the customer generation fails, backup electricity is not supplied from the electricity grid; or (iii) there is physical assurance that the Load served by the customer generation will be curtailed concurrently and commensurately with an outage of the customer generation.

### 40.2 Submission of Annual and Monthly Resource Adequacy Plan.

#### 40.2.1 Annual Resource Adequacy Plan.

Each Scheduling Coordinator for a Load Serving Entity serving Load within the ISO Control Area must provide the ISO with an annual Resource Adequacy Plan. The annual Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area shall be submitted on the schedule and in the form approved by the CPUC. The annual Resource Adequacy Plan provided to the ISO by Scheduling Coordinators for the non-CPUC Load Serving Entity or Entities for whom they schedule Demand within the ISO Control Area shall be submitted no later than September 30th of each year and in the form set forth on the ISO Website. Other than for good cause, the form of the Resource Adequacy Plan and the date for submission for the CPUC Load Serving Entities and the Non-CPUC Load Serving Entities should be identical. The annual Resource Adequacy Plan must identify the Resource Adequacy Resources that will be relied upon to satisfy the Planning Reserve Margin under Section 40.4, or portion thereof as established by the CPUC or applicable Local Regulatory Authority, and must apply the Net Qualifying Capacity requirements of Section 40.5.2.

**40.2.2 Monthly Resource Adequacy Plan.**

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

**40.2.3 Resource Adequacy Plan Compliance.**

The ISO will evaluate whether each monthly Resource Adequacy Plan submitted by a Scheduling

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

**40.2.4 Reporting of Enforcement Actions.**

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

**40.2.5 Compliance with Submission Obligation.**

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

**40.3 Demand Forecasts.**

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

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

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

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

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

**40.4 Planning Reserve Margin.**

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

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

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

c. For Scheduling Coordinators representing Load Serving Entities for which the CPUC or other Local Regulatory Authority has not established a Planning Reserve Margin, the Planning Reserve Margin shall be no less than 115% of the peak hour of the month in the Demand Forecast set forth in Section 40.3.

**40.5 Determination of Resource Adequacy Capacity.**

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

**40.5.1 Qualifying Capacity.**

Qualifying Capacity is the capacity from a resource prior to application of the Net Capacity provisions of Section 40.5.2. The criteria for determining the types of resources that may be eligible to provide Qualifying Capacity and for calculating Qualifying Capacity from eligible resource types may be established by the CPUC or other applicable Local Regulatory Authority and provided to the ISO. Only if such criteria are not provided by the CPUC or other Local Regulatory Authority, Section 40.13 will apply. The ISO shall use the criteria provided by the CPUC, other Local Regulatory Authority or, if necessary, Section 40.13, to determine and verify, if necessary, the Qualifying Capacity of all resources listed in a Resource Adequacy Plan; however, to the extent a resource is listed by one or more Scheduling Coordinators in their respective Resource Adequacy Plans, which apply the criteria of more than one regulatory entity that leads to conflicting Qualifying Capacity values for that resource, the ISO will apply the respective Qualifying Capacity formulas applicable for each Load Serving Entity.

**40.5.2 Net Qualifying Capacity.**

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

**40.5.2.1 Deliverability Within the ISO Control Area.**

In order to determine Net Qualifying Capacity from a Generating Unit, the ISO will determine that the Generating Unit is able to serve the aggregate of Load by means of a deliverability analysis. The deliverability analysis shall focus on peak Demand conditions. The ISO will review its input assumptions and draft results with Market Participants before completing its determination. The ISO will update the deliverability baseline analysis on an annual basis. The ISO will coordinate with the CPUC and other Local Regulatory Authorities so that the deliverability analysis can be utilized in the development of Resource Adequacy Plans. To the extent the deliverability analysis shows that the Qualifying Capacity of a Generating Unit is not deliverable to the aggregate of Load under the conditions studied, the Qualifying Capacity of the Generating Unit will be reduced on a MW basis for the capacity that is undeliverable. The ISO will utilize its interconnection process and procedures under Section 25 of the ISO Tariff to prevent degradation of the deliverability of an existing Generating Unit that could result from the interconnection of additional Generation.

**40.5.2.2 Deliverability of Imports.**

This Section 40.5.2.2 shall apply only to Resource Adequacy Plans covering the period through December 31, 2007, unless superseded earlier by alternative ISO Tariff provisions. The ISO shall establish for 2006 for each branch group the total import capacity values to be allocated to Load Serving Entities serving Load in the ISO Control Area for Resource Adequacy planning purposes, and will update those values for 2007. The updated import capacity values shall be posted on the ISO Website. Import capacity associated with (i) Existing Transmission Contracts and (ii) Encumbrances and Transmission Ownership Rights shall be reserved for holders of such commitments as part of the deliverability study and will not be subject to allocation under this Section. For the purpose of accounting for import Resource Adequacy Capacity, the import capability of the system will be allocated by branch group by the ISO (1) to non-CPUC Load Serving Entities individually and (2) to the CPUC Load Serving Entities as an aggregated allocation, which will be subject to the allocation rules of the CPUC.

For 2006, the allocation will be as follows:

a. Non-CPUC Load Serving Entities will receive an allocation on a particular branch group equal to each entity's resource commitments outside the ISO Control Area, as of October 27, 2005 that utilizes the particular branch group through calendar year 2006.

b. CPUC Load Serving Entities will receive an aggregate import value by branch group that is equal to the maximum value for each branch group minus import capacity associated with (i) Existing Transmission Contracts, (ii) Encumbrances and Transmission Ownership Rights, and (iii) resource commitments outside the ISO Control Area of non-CPUC Load Serving Entities, as of October 27, 2005 as provided for in Section 40.5.2.2(a).

For 2007, the allocation will be as follows:

c. Non-CPUC Load Serving Entities will receive an allocation on a particular branch group equal to each entity's resource commitments outside the ISO Control Area, as of March 10, 2006 that utilizes the particular branch group through calendar year 2007.

d. CPUC Load Serving Entities will receive an aggregate import value by branch group that is equal to the maximum value for each branch group minus import capacity associated with (i) Existing Transmission Contracts, (ii) Encumbrances and Transmission Ownership Rights, and (iii) resource commitments outside the ISO Control Area of non-CPUC Load Serving Entities, as of March 10, 2006 as provided for in Section 40.5.2.2(c).

This allocation does not guarantee or result in any actual transmission service being allocated and is only used for determining the maximum Resource Adequacy Capacity that can be credited towards satisfying a Scheduling Coordinator's Resource Adequacy obligation. Upon the request of the ISO, Scheduling Coordinators must provide the ISO with information on existing import contracts and any trades or sales of their load share allocation. Such information will be subject to the confidentiality provisions of this ISO Tariff. The ISO will inform the CPUC or other Local Regulatory Authority of Resource Adequacy Plan submitted by a Scheduling Coordinator for a Load Serving Entity under their respective jurisdiction that exceeds its allocation of import capacity.

**40.6 Submission of Supply Plans.**

Scheduling Coordinators representing Resource Adequacy Resources supplying Resource Adequacy Capacity shall provide the ISO with annual and monthly Supply Plans. The annual Supply Plan shall be provided by September 30th of each year. The monthly Supply Plan shall be provided on the last business day of the second month prior to the compliance month (e.g., March 31 for May). Both the annual and monthly Supply Plans shall be provided in the form set forth on the ISO's Website, listing their commitments to provide Resource Adequacy Capacity to any Load Serving Entity or Entities for the reporting period. Such plans will be accorded protection in accordance with the confidentiality provisions of this ISO Tariff.

**40.6.1 Compliance with Supply Plan Obligation.**

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

**40.6A Availability of Resource Adequacy Resources.**

**40.6A.1 Applicability.**

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

**40.6A.2 Available Generation.**

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

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

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

**40.6A.4 Obligation to Offer Available Capacity.**

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

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

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

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

### 40.6A.6 Resource Adequacy Resource Obligation Process.

Resource Adequacy Resources may seek a waiver of the obligation to offer all Available Generation, as set forth in Section 40.6A.4 of this ISO Tariff, for one or more of their units. All Resource Adequacy

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

The hours for which waivers are not granted shall constitute Waiver Denial Periods. A Waiver Denial Period shall be extended as necessary to accommodate the unit minimum up and down times. Units shall be on-line in real time during Waiver Denial Periods, or they will be in violation of the availability. Exceptions shall be allowed for verified forced outages or as otherwise set forth in Section 40.6A.5. The ISO may revoke waivers as necessary due to outages, changes in Load forecasts, or changes in system conditions. The ISO shall determine which waiver(s) will be revoked, and shall notify the relevant Scheduling Coordinator(s). The ISO shall inform a Resource Adequacy Resource that its Waiver request has been approved, disapproved or revoked, and shall provide the Resource Adequacy Resource with the reason(s) for the decision, which reasons shall be non-discriminatory apart from the status of whether the unit is a Resource Adequacy Resource. The ISO will: (1) notify Resource Adequacy Resources of the ISO decisions on pending Waiver requests received no later than 10:00 a.m. (beginning of Hour Ending 11) no later than 11:30 a.m. (middle of Hour Ending 12) on the day before the operating day for which the Waivers are requested; (2) at any time but no later than 11:30 a.m. on the following day, notify Resource Adequacy Resources of the ISO decisions on Waiver requests that were submitted to the ISO after 10:00 a.m. (beginning of Hour Ending 11) on the day before; (3) end Waiver Denial Periods at any time; (4) revoke Waivers at any time, while making best attempts to revoke a Waiver at least 90 minutes prior to the time a unit would be required to be on-line generating at its Pmin; and (5) revoke a waiver denial for a Short-Start Resource Adequacy Resource at any time and such revocation will be communicated via a ISO real-time dispatch or unit commitment instruction.

**40.6A.7 Penalties for Non-Compliance.**

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

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

**40.6B.1 Eligibility.**

Except as set forth below, Resource Adequacy Resources that are Generating Units and System Units for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity shall be eligible to recover Un-Recovered Minimum Load Costs during Waiver Denial Periods. Units from Resource Adequacy Resources that incur Minimum Load Costs during hours for which the ISO has granted to them a waiver shall not be eligible to recover such costs for such hours. When a Resource Adequacy Resource has a Final Hour-Ahead Energy Schedule, the Resource Adequacy Resource shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. When, on a 10-minute Settlement Interval basis, a Resource Adequacy Resource generating at minimum load in compliance with the supply obligation, produces a quantity of Energy that varies from its minimum operating level by more than the Tolerance Band, the Resource Adequacy Resource shall not be eligible to recover Minimum Load Costs for any such Settlement Intervals during hours within a Waiver Denial Period. When, on a Settlement Interval basis, a Resource Adequacy Resource produces a quantity of Energy above minimum load due to an ISO Dispatch Instruction, the Resource Adequacy Resource shall recover its Un-Recovered Minimum Load Costs as set forth in this Section and its bid costs, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band. Subject to the foregoing eligibility restrictions set forth in this section. the ISO shall guarantee recovery of the Minimum Load Costs of an otherwise eligible Resource Adequacy Resource for each Settlement Interval during hours within a Waiver Denial Period as follows: (1) First, ISO will pre-dispatch for real time the minimum load Energy from Resource Adequacy Resources that have been denied waivers for each hour within a Waiver Denial Period; (2) This minimum load Energy will be accounted as Instructed Imbalance Energy for each Settlement Interval within the relevant hour and be settled at the Resource-Specific Settlement Interval Ex Post Price; (3) To the extent the Instructed Imbalance Energy payments are not sufficient to cover the generator's Minimum Load Cost as defined in Section 40.6B.3 of this ISO Tariff, the generator will also receive an uplift payment for its Un-Recovered Minimum Load Cost compensation for the relevant eligible Settlement Intervals of hours during the Waiver Denial Period that the unit runs at minimum load in compliance with the Resource Adequacy offer obligation; and (4) To the extent the Generator is dispatched for real time Imbalance Energy above its minimum load for any Dispatch Interval within an hour during the Waiver Denial Period, the Generator will be eligible for Bid Cost Recovery, as set forth in Section 11.2.4.1.1.1.

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

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

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

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

**40.6B.4 Un-Recovered Minimum Load Costs.**

The Un-Recovered Minimum Load Costs for each hour of Waiver Denial Period shall be calculated as the difference between: (1) a resource's Minimum Load Costs as calculated in this Section for the same Settlement Interval and (2) the Imbalance Energy payment for a resource's minimum load energy in the Settlement Interval. If the Imbalance Energy payment for minimum load energy exceeds the Minimum Load Costs, then there are no Un-Recovered Minimum Load Costs. The Minimum Load Costs shall be calculated as the sum, for all eligible hours in the Waiver Denial Period and Settlement Periods in which the unit generated in response to an ISO Dispatch Instruction, of: (1) the product of the unit's average heat rate (as determined by the ISO from the data provided in accordance with Section 40.10) at the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC and the gas price determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Resource Adequacy Resource is not served from one of those three Service Areas; and (2) the product of the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC; and $6.00/MWh.

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

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

(1) if the Generating Unit or System Unit for which the MSS Operator has contracted to supply Resource Adequacy Capacity to another entity was operating to meet local reliability requirements, the incremental locational cost shall be allocated to the Participating TO in whose PTO Service Territory the unit is located, or, where the unit is located outside the PTO Service Territory of any Participating TO, to the Participating TO or Participating TOs whose PTO Service

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

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

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

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

b. finally, all remaining costs not allocated per (a) shall be allocated to each Scheduling Coordinator in proportion to the sum of that Scheduling Coordinator's monthly

Control Area Gross Load and Demand within California outside the ISO Control Area that is served by exports to the monthly sum of the ISO Control Area Gross Load and the projected Demand within California outside the ISO Control Area that is served by exports from the ISO Control Area of all Scheduling Coordinators.

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

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

**40.~~1~~7 FERC Must-Offer Obligations.**

**40.~~1~~7.1 Applicability.**

The requirements of Section 40.~~1~~7 shall apply to (a) all Participating Generators, and (b) all persons, regardless of whether the person is a "public utility" as defined in Section 201 of the Federal Power Act, that own or control one or more non-hydroelectric Generating Units~~,~~ or System Units or System Resources located in California from which energy or capacity is either: (i) sold through any market operated by the ISO, or (ii) transmitted over the ISO Controlled Grid. Each person described in this Section 40.~~1~~7.1 is referred to in the ISO Tariff as a "FERC Must-Offer Generator." The requirements of this Section 40.~~1~~7 shall apply to all non-hydroelectric Generating Units located in California that are owned or controlled by a FERC Must-Offer Generator.

**40.~~1~~7.2 Available Generation.**

For the purposes of ~~this~~ Section 40.~~1~~7, a FERC Must-Offer Generator's "Available Generation" from a non-hydroelectric Generating Unit shall be: (a) the Generating Unit's maximum operating level adjusted for any outages or reductions in capacity reported to the ISO in accordance with Section ~~7~~ 9.3.9 or 40.~~1~~7.3 and for any limitations on the Generating Unit's operation under applicable law, including contractual obligations, which shall be reported to the ISO, (b) minus the Generating Unit's scheduled operating ~~point~~ level as identified in the ISO's Final Hour-Ahead Schedule, (c) minus the Generating Unit's or System Unit's capacity committed to provide Ancillary Services to the ISO either through the ISO's Ancillary Services market or through self-provision by a Scheduling Coordinator, and (d) minus the capacity of the Generating Unit committed to deliver Energy or provide Operating Reserve to the FERC Must-Offer Generator's Native Load.

**40.~~1~~7.3 Reporting Requirements for Non-Participating Generators.**

So that the ISO may determine the Available Generation of all FERC Must-Offer Generators, FERC Must-Offer Generators that are not Participating Generators shall be required to file with the ISO, for each non-hydroelectric Generating Unit located in California they own or control: (i) the Generating Unit's minimum operating level; (ii) the Generating Unit's maximum operating level; and (iii) the Generating Unit's ramp rates at all operating levels; and (iv) such other information the ISO determines is necessary to determine available generation and to dispatch FERC Must-Offer Generators. In addition, FERC Must-Offer Generators that are not Participating Generators must, consistent with the notification obligations of Participating Generators and in order to comply with the intent of this Section 40.7~~1~~, notify the ISO, as soon as practicable, of any Planned Maintenance Outages, Forced Outages, Force Majeure Event outages or any other reductions in their maximum operating levels or Resource Adequacy Capacity during the relevant month.

**40.~~1~~7.4 Obligation To Offer Available ~~Capacity~~Generation.**

Except as set forth in Sections 40.7.5 and 40.7.6 ~~40.1.6~~, all FERC Must-Offer Generators shall offer to sell in the ISO's Real Time Market for Imbalance Energy, in all hours, all their Available Generation as defined in Section 40.~~1~~7.2.

**40.~~1~~7.5 Submission of Bids and Applicability of the Proxy Price.**

For each Operating Hour, FERC Must-Offer Generators shall submit Supplemental Energy bids for all of their Available Generation to the ISO in accordance with Section 34.2. In addition, the ISO shall calculate for each gas-fired FERC Must-Offer Generator, in accordance with Section ~~34.9~~40.10.1, a Proxy Price for Energy.

If a FERC Must-Offer Generator fails to submit a Supplemental Energy bid for any portion of its Available Generation for any Dispatch Interval, the unbid quantity of the FERC Must-Offer Generator's Available Generation will be deemed by the ISO to be bid at the FERC Must-Offer Generator's Proxy Price for that hour if: (i) the applicable Generating Unit is a gas-fired unit and (ii) the FERC Must-Offer Generator has provided the ISO with adequate data in compliance with Sections 40.~~1~~7.7 and 40.~~1~~7.3 for the applicable Generating Unit. For all other Generating Units owned or controlled by a FERC Must-Offer Generator, the unbid quantity of the FERC Must-Offer Generator's Available Generation will be deemed by the ISO to be bid and settled in accordance with Section 11.2. In order to dispatch resources providing Imbalance Energy in proper merit order, the ISO will insert this unbid quantity into the FERC Must-Offer Generator's Supplemental Energy bid curve above any lower-priced segments of the bid curve and below any higher-priced segments of the bid curve as necessary to maintain a non-decreasing bid curve over the entire range of the FERC Must-Offer Generator's Available Generation.

**40.~~1~~7.6 FERC Must-Offer Obligation Process.**

FERC Must-Offer Generators may seek a waiver of the obligation to offer all available capacity, as set forth in Section 40.~~1~~7.4 of this ISO Tariff, for one or more of their Generating Units or System Units.

All FERC Must-Offer Generators obligated under the must-offer obligation that have not submitted Day-Ahead Energy Schedules will be deemed to have requested a waiver, either implicitly or explicitly, of the obligation to offer all ~~available capacity~~Available Generation. If conditions permit, ~~and at the ISO's non-discriminatory and~~the ISO may, at its sole discretion, ~~the ISO may~~ grant waivers and allow a FERC Must-Offer Generator to remove one or more Generating Units or System Units from service. In doing so, the ISO will first grant waivers to FERC Must-Offer Generators, on a non-discriminatory basis, that are not also Resource Adequacy Resources and then, if permissible, the ISO may grant waivers to Resource Adequacy Resources on a non-discriminatory basis.

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

**40.~~1.6.1~~8 Recovery of Minimum Load Costs By FERC Must-Offer Generators.**

**40.~~1.6.1.1~~8.1 Eligibility.**

Except as set forth below, Generating Units shall be eligible to recover Minimum Load Costs during Waiver Denial Periods. Units from FERC Must-Offer Generators that incur Minimum Load Costs during hours for which the ISO has granted to them a waiver shall not be eligible to recover such costs for such hours. When a FERC Must-Offer Generator has a Final Hour-Ahead Energy Schedule, the FERC Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such hours within a Waiver Denial Period. When, on a 10-minute Settlement Interval basis, a FERC Must-Offer Generator generating at minimum ~~load~~ operating level in compliance with the must-offer obligation, produces a quantity of Energy that varies from its minimum operating level by more than the Tolerance Band, the FERC Must-Offer Generator shall not be eligible to recover Minimum Load Costs for any such Settlement Intervals during hours within a Waiver Denial Period. When, on a Settlement Interval basis, a FERC Must-Offer Generator's resource produces a quantity of Energy above minimum load due to an ISO Dispatch

Instruction, the FERC Must-Offer Generator shall recover its Minimum Load Costs as set forth in this Section and its bid costs, as set forth in Section 11.2.4.1.1.1, for any such Settlement Intervals during hours within a Waiver Denial Period, irrespective of deviations outside of its Tolerance Band. Subject to the foregoing eligibility restrictions set forth in this section, the ISO shall guarantee recovery of the Minimum Load Costs of an otherwise eligible FERC Must-Offer Generator for each Settlement Interval during hours within a Waiver Denial Period as follows: (1) First, ISO will pre-dispatch for real time the minimum load Energy from FERC Must-Offer Generators that have been denied waivers for each hour within a Waiver Denial Period; (2) This minimum load Energy will be accounted as Instructed Imbalance Energy for each Settlement Interval within the relevant hour and be settled at the Resource-Specific Settlement Interval Ex Post Price; (3) ~~To the extent the Instructed Imbalance Energy payments are not sufficient to cover t~~The generator's Minimum Load Cost as defined in Section 40.~~1.6.1.2~~8.4 of this ISO Tariff, the generator will also receive a~~n uplift~~ payment for its Minimum Load Cost compensation for the relevant eligible Settlement Intervals of hours during the Waiver Denial Period that the Generating Unit runs at minimum load in compliance with the must-offer obligation; and (4) To the extent the Generator is dispatched for real time Imbalance Energy above its minimum load for any Dispatch Interval within an hour during the Waiver Denial Period, the Generator will be eligible for Bid Cost Recovery, as set forth in Section 11.2.4.1.1.1.

**40.~~1.6.1.1.1~~8.2 Payments for Imbalance Energy Above the Minimum Operating Level for Generating Units Eligible to Be Paid Minimum Load Costs.**

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

**40.~~1.6.1.1.2~~8.3 Payments for Imbalance Energy for the Minimum Operating Level for Generating Units Eligible to Be Paid Minimum Load Costs.**

A Generating Unit operating at or near its minimum operating level during a Waiver Denial Period either

(1) without a forward Schedule for its minimum operating level Energy or (2) with a Schedule to a special-purpose Demand ID for the sole purpose of Scheduling the minimum operating level Energy shall be paid, in addition to being paid its Minimum Load Costs subject to eligibility as set forth in Section 40.8.1~~1.6.1.1~~, an amount equal to the Resource Specific Settlement Interval Ex Post Price times the amount of Energy actually delivered.

**40.~~1.6.1.2~~8.4 Minimum Load Costs.**

The Minimum Load Costs shall be calculated as the sum, for all eligible hours in the Waiver Denial Period and Settlement Periods in which the unit generated in response to an ISO Dispatch Instruction, of: (1) the product of the unit's average heat rate (as determined by the ISO from the data provided in accordance with Section 40.~~1.7~~10) at the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC and the gas price determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the FERC Must-Offer Generator is not served from one of those three Service Areas; and (2) the product of the unit's relevant minimum operating level or Dispatchable minimum operating level as set forth in the ISO Master File or as amended through notification to the ISO via SLIC; and $6.00/MWh.

**40.8.5 [Not Used]~~40.1.6.1.3 Invoicing Minimum Load Costs.~~**

~~The ISO shall determine each Scheduling Coordinator's Minimum Load Costs and make payments for these costs as part of the ISO's market settlement process. Scheduling Coordinators may submit to the ISO data detailing the hours for which they are eligible to recover Minimum Load Costs. Scheduling Coordinators who elect to submit data on hours they are eligible to recover Minimum Load Costs must: 1) use the Minimum Load Cost invoice template posted on the ISO Home Page, and 2) submit the invoice on or before fifteen (15) Business Days following the last Trading Day in the month in which such costs~~

~~were incurred, except that Scheduling Coordinators seeking reimbursement for Minimum Load Costs incurred between May 29, 2001, and June 30, 2002 must submit their data to the ISO by August 5, 2002.~~

**40.~~1.6.1.4~~8.6 Allocation of Minimum Load Costs.**

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

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

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

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

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

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

**40.~~1.6.1.5~~8.7 Payment Of Available Generation ~~Capacity~~ Under The FERC Must-Offer Obligation.**

Available Generation ~~capacity~~ that is required to be offered to the Real-Time Market, if dispatched by the ISO, shall be settled as follows: the actual amount of the dispatched Energy shall be settled at the applicable Instructed Imbalance Energy Market Clearing Price. Minimum Load Cost compensation shall be paid for all otherwise eligible hours within the Waiver Denial Period, as defined in Section 40.8.1~~1.6.1.1~~, that the unit generated Energy above minimum operating level~~load~~ in compliance with ISO Dispatch Instructions.

**40.~~1.6.2~~9 Criteria for Issuing Must-Offer Waivers.**

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

**40.~~1.7~~10 Requirement of FERC Must-Offer Generators to File Heat Rate and Emissions Rate Data.**

Resource Adequacy Resources and FERC Must-Offer Generators, as defined in ~~Section 40.1 of~~ this ISO Tariff, that own or control gas-fired Generating Units or System Units must file with the ISO and the FERC, on a confidential basis, the heat rates and emissions rates for each gas-fired Generating Unit or System Unit that they own or control. Heat rate and emissions rate data shall be provided in the format specified by the ISO as posted on the ISO ~~Home Page~~Website. Heat rate data provided to comply with this requirement shall not include start-up or minimum load fuel costs. Resource Adequacy Resources and FERC Must-Offer Generators must also file periodic updates of this data upon the direction of either FERC or the ISO. The ISO will treat the information provided to the ISO in accordance with this s~~S~~ection ~~40.1.7~~ as confidential and will apply the procedures in Section 20.4 of this ISO Tariff with regard to requests for disclosure of such information.

**40.~~1.8~~10.1 Calculation of the Proxy Price.**

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

**40.~~1.9~~11 Emissions Costs.**

**40.~~1.9.1~~11.1 Obligation to Pay Emissions Cost Charges.**

Each Scheduling Coordinator shall be obligated to pay a charge which will be used to pay the verified Emissions Costs incurred by a Resource Adequacy Resource or FERC Must-Offer Generator as a direct result of an ISO Dispatch i~~I~~nstruction, in accordance with this Section 40~~.1.9~~. The ISO shall levy this administrative charge (the "Emissions Cost Charge") each month, against all Scheduling Coordinators based upon each Scheduling Coordinator's Control Area Gross Load and Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area. Scheduling Coordinators shall make payment for all Emissions Cost Charges in accordance with the ISO Payments Calendar.

**40.~~1.9.2~~11.2 Emissions Cost Trust Account.**

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

**40.~~1.9.3~~11.3 Rate For the Emissions Cost Charge.**

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

**40.~~1.9.4~~11.4 Adjustment of the Rate For the Emissions Cost Charge.**

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

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

(b) the difference, if any, between the projections of the Emissions Costs incurred by Resource Adequacy Resources or FERC Must-Offer Generators as a direct result of ISO Dispatch Iinstructions and the actual Emissions Costs incurred by Resource Adequacy

Resources or FERC Must-Offer Generators as a direct result of ISO Dispatch ~~i~~Instructions as invoiced to the ISO and verified in accordance with this Section 40.~~1.9~~11; and

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

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

**40.~~1.9.5~~11.5 Credits and Debits of Emissions Cost Charges Collected from Scheduling Coordinators.**

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

**40.~~1.9.6~~11.6 Submission of Emissions Cost Invoices.**

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

**40.~~1.9.7~~11.7 Payment of Emissions Cost Invoices.**

The ISO shall pay Scheduling Coordinators for all Emissions Costs submitted in an Emissions Cost Invoice and demonstrated to be a direct result of an ISO Dispatch ~~I~~instruction. If the Emissions Costs indicated in the applicable air quality districts' final invoice statements include emissions produced by operation not resulting from ISO Dispatch ~~I~~instructions, the ISO shall pay an amount equal to Emissions Costs multiplied by the ratio of the MWh associated with ISO Dispatch ~~I~~instruction to the total MWh associated with such Emissions Costs. The ISO shall pay Emissions Cost Invoices each month in accordance with the ISO Payments Calendar from the funds available in the Emissions Cost Trust Account. To the extent there are insufficient funds available in Emissions Cost Trust Account in any month to pay all Emissions Costs submitted in an Emissions Cost Invoice and demonstrated to be a direct result of an ISO Dispatch ~~I~~instruction, the ISO shall make pro rata payment of such Emissions Costs and shall adjust the rate at which the ISO will assess the Emissions Cost Charge in accordance with Section 40.~~1.9.4~~11.4. Any outstanding Emissions Costs owed from previous months will be paid in the order of the month in which such costs were invoiced to the ISO. The ISO's obligation to pay Emissions Costs is limited to the obligation to pay Emissions Cost Charges received. All disputes concerning payment of Emissions Cost Invoices shall be subject to ISO ADR Procedures, in accordance with Section 13 of this ISO Tariff.

**40.~~1.10~~12 Start-Up Costs.**

**40.~~1.10.1~~12.1 Obligation to Pay Start-Up Cost Charges.**

Each Scheduling Coordinator shall be obligated to pay a charge which will be used to pay the verified Start-Up Costs incurred by a Resource Adequacy Resource or FERC Must-Offer Generator as a direct result of an ISO Dispatch ~~I~~instruction, in accordance with this Section 40.~~1.10~~12. Such Start-Up Costs shall include (1) fuel and (2) auxiliary power. The ISO shall levy this charge (the "Start-Up Cost Charge"), each month, against all Scheduling Coordinators based upon each Scheduling Coordinator's Control Area Gross Load and Demand within California outside of the ISO Control Area that is served by exports from the ISO Control Area. Scheduling Coordinators shall make payment for all Start-Up Cost Charges in accordance with the ISO Payments Calendar.

**40.~~1.10.2~~12.2 Start-Up Cost Trust Account.**

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

**40.~~1.10.3~~12.3 Rate For the Start-Up Cost Charge.**

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

**40.~~1.10.4~~12.4 Adjustment of the Rate For the Start-Up Cost Charge.**

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

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

(b) the difference, if any, between the projections of the Start-Up Costs incurred by FERC Must-Offer Generators as a direct result of ISO Dispatch Iinstructions and the actual Start-Up Costs incurred by Resource Adequacy Resource or FERC Must-Offer Generators as a direct result of ISO Dispatch Iinstructions as invoiced to the ISO and verified in accordance with this Section 40.~~1.10~~12; and

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

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

**40.~~1.10.5~~12.5 Credits and Debits of Start-Up Cost Charges Collected from Scheduling Coordinators.**

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

**40.~~1.10.6~~12.6 Submission of Start-Up Cost Invoices.**

Scheduling Coordinators for Resource Adequacy Resources or FERC Must-Offer Generators that incur Start-Up Costs as a direct result of an ISO Dispatch ~~i~~Instruction or if the ISO revokes a waiver from compliance with the FERC must-offer obligation while the unit is off-line in accordance with Section 40.6A.6 or 40.~~1.6~~7.6 of this ISO Tariff, and Scheduling Coordinators for Generating Units or System Units operating under Condition 2 of the relevant RMR Contract which are called out-of-market in accordance with Section 11.2.4.2 of this ISO Tariff may submit to the ISO an invoice in the form specified on the ISO ~~Home Page~~Website (the "Start-Up Cost Invoice") for the recovery of such Start-Up Costs. Such Start-Up Costs shall not exceed the costs which would be incurred within the start-up time for a unit specified in Schedule 1 of the Participating Generator Agreement. Start-Up Cost Invoices shall use the applicable proxy figure for natural gas costs as determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Resource Adequacy Resource or FERC Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas. Start-Up Cost Invoices shall specify the amount of auxiliary power used during the start-up and the actual price paid for that power. Start-Up Cost Invoices shall not include any Start-Up Costs specified in an RMR Contract for a unit owned or controlled by a FERC Must-Offer Generator.

**40.~~1.10.7~~12.7 Payment of Start-Up Cost Invoices.**

The ISO shall pay Scheduling Coordinators for all Start-Up Costs submitted in a Start-Up Cost Invoice and demonstrated to be a direct result of an ISO Dispatch ~~I~~instruction. The ISO shall pay such Start-Up Cost Invoices each month in accordance with the ISO Payments Calendar from the funds available in the Start-Up Cost Trust Account. To the extent there are insufficient funds available in the Start-Up Cost Trust Account in any month to pay all Start-Up Costs submitted in a Start-Up Cost Invoice and demonstrated to be a direct result of an ISO Dispatch ~~I~~instruction, the ISO shall make pro rata payment of such Start-Up Costs and shall adjust the rate at which the ISO will assess the Start-Up Cost Charge in accordance with Section 40.~~1.10.4~~12.4. Any outstanding Start-Up Costs owed from previous months will be paid in the order of the month in which such costs were invoiced to the ISO. The ISO's obligation to pay Start-Up Costs is limited to the obligation to pay Start-Up Cost Charges received. All disputes concerning payment of Start-Up Cost Invoices shall be subject to ISO ADR Procedures, in accordance with Section 13 of this ISO Tariff.

**40.13 ISO Default Qualifying Capacity Criteria.**

**40.13.1 Applicability.**

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

**40.13.2 Nuclear and Thermal.**

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

**40.13.3 Hydro.**

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

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

**40.13.4 Unit-Specific Contracts.**

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

**40.13.5 Contracts with Liquidated Damage Provisions.**

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

**40.13.6 Wind and Solar.**

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

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

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

**40.13.7 Geothermal.**

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

**40.13.8 Treatment of Qualifying Capacity for QFs.**

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

**40.13.9 Participating Load Resources.**

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

**40.13.10 Jointly-Owned Facilities.**

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

**40.13.11 Facilities Under Construction.**

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

**40.13.12 System Resources.**

**40.13.12.1 Dynamically Scheduled System Resources.**

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

**40.13.12.2 Non-Dynamically Scheduled System Resources.**

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

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

**41~~0.2~~ Procurement of RMR.**

**42~~0.3~~ Assurance of Adequate Generation and Transmission to meet Applicable Operating and Planning Reserve.**

**42.1~~0.3.1~~ Generation Planning Reserve Criteria.**

Generation planning reserve criteria shall be met as follows:

**42.1.1~~0.3.1.1~~** On an annual basis, the ISO shall prepare a forecast of weekly Generation capacity and weekly peak Demand on the ISO Controlled Grid. This forecast shall cover a period of twelve months and be posted on the WEnet and the ISO may make the forecast available in other forms at the ISO's option.

**42.1.2~~0.3.1.2~~** If the forecast shows that the applicable WECC/NERC Reliability Criteria can be met during peak Demand periods, then the ISO shall take no further action.

**42.1.3~~0.3.1.3~~** If the forecast shows that the applicable WECC/NERC Reliability Criteria cannot be met during peak Demand periods, then the ISO shall facilitate the development of market mechanisms to bring the ISO Controlled Grid during peak periods into compliance with the Applicable Reliability Criteria (or such more stringent criteria as the ISO may impose pursuant to Section 7.2.2.2). The ISO shall solicit bids for Replacement Reserve in the form of Ancillary Services, short-term Generation supply contracts of up to one (1) year with Generators, and Load curtailment contracts giving the ISO the right to reduce the Demands of those parties that win the contracts when there is insufficient Generation capacity to satisfy those Demands in addition to all other Demands. The curtailment contracts shall provide that the ISO's curtailment rights can only be exercised after all available Generation capacity has been fully utilized unless the exercise of such rights would allow the ISO to satisfy the Applicable Reliability Criteria at lower cost, and the curtailment rights shall not be exercised to stabilize or otherwise influence prices for power in the Energy markets.

**42.1.4~~0.3.1.4~~** If Replacement Reserve, short-term Generation supply contracts or curtailment contracts are required to meet Applicable Reliability Criteria, the ISO shall select the bids that permit the satisfaction of those Applicable Reliability Criteria at the lowest cost.

**42.1.5~~0.3.1.5~~** Notwithstanding the foregoing, if the ISO concludes that it may be unable to comply with the Applicable Reliability Criteria, the ISO shall, acting in accordance with Good Utility Practice, take such steps as it considers to be necessary to ensure compliance, including the negotiation of contracts through processes other than competitive solicitations. The steps can include the negotiation of contracts for Ancillary Services on a real time basis. If the ISO is unable to obtain such Ancillary Services from within the ISO Controlled Grid, the ISO may solicit Ancillary Services from other Control Areas on a real-time basis.

**42.1.6~~0.3.1.6~~** The ISO may, in addition to the required annual forecast, publish a forecast of the peak Demands and Generation resources for two or more additional years. This forecast would be for information purposes to allow Market Participants to take appropriate steps to satisfy the Applicable Reliability Criteria, and would not be used by the ISO to determine whether additional resources are necessary.

**42.1.7~~0.3.1.7~~** In fulfilling its requirement to ensure that the applicable Generation planning reserve criteria are satisfied, the ISO shall rely to the maximum extent possible on market forces.

**42.1.8~~0.3.1.8~~** Except where and to the extent that such costs are recovered from Scheduling Coordinators pursuant to Section 8, and except as provided in Section ~~40.3.1.9~~42.1.9, all costs incurred by the ISO in any hour pursuant to any contract entered into under this Section ~~40.3.1~~42.1 shall be charged to each Scheduling Coordinator pro rata based upon the same proportion as the Scheduling Coordinator's metered hourly Demand (including exports) bears to the total metered hourly Demand (including exports) served in that hour.

**42.1.9~~0.3.1.9~~** Costs incurred by the ISO pursuant to any contract entered into under this Section ~~40.3.1~~42.1 for resources to meet any portion of the anticipated difference between forward schedules and the real-time deviations from those schedules shall be charged to each Scheduling Coordinator pro rata based upon the same proportion as the Scheduling Coordinator's obligation for deviation Replacement Reserve in the hour, determined in accordance with Section 8.12.3A bears to the total deviation Replacement Reserve in that hour.

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secured generating capacity in accordance with this Section 4.9.16.2., the Scheduling Coordinator for the MSS Operator shall not be obligated to bear any share of the ISO's costs for any summer Demand reduction program or for any summer reliability Generation procurement program pursuant to ISO Tariff Section 42.1.8 for the calendar year for which the demonstration is made.

**4.9.16.3** If the ISO is compensating Generating Units for Emissions Costs, Start-Up Fuel Costs and Minimum Load Costs, and if MSS Operator charges the ISO for the Emissions Costs, Start-Up Fuel Costs and Minimum Load Costs, of the Generating Units serving the Load of the MSS, then the Scheduling Coordinator for the MSS shall bear its proportionate share of the total amount of those costs incurred by the ISO based on the MSS gross metered Demand and exports and the Generating Units shall be made available to the ISO through the submittal of Supplemental Energy bids. If the MSS Operator chooses not to charge the ISO for the Emissions Costs, Start-Up Fuel Costs and Minimum Load Costs of the Generating Units serving the Load of the MSS, then the Scheduling Coordinator for the MSS shall bear its proportionate share of the total amount of those costs incurred by the ISO based on the MSS's net metered Demand and exports. The MSS Operator shall make the election whether to charge the ISO for these costs on an annual basis on November 1 for the following calendar year.

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

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

**8.4 Technical Requirements for Providing Ancillary Services.**

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

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

**8.7 Scheduling of Units to Provide Ancillary Services.**

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

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

Once the ISO has given Scheduling Coordinators notice of the Day-Ahead and Hour-Ahead Schedules, these schedules represent binding commitments made in the markets between the ISO and the Scheduling Coordinators concerned, subject to any amendments issued as described above. Any minimum energy input and output associated with Regulation and Spinning Reserve services shall be the responsibility of the Scheduling Coordinator, or provided in accordance with the must-offer obligation as set forth in Section 40.7, as the ISO's auction does not compensate the Scheduling Coordinator for the minimum energy output of Generating Units or System Units, if any, bidding to provide these services.

Accordingly, except as set forth under Section 40.7, the Scheduling Coordinators shall adjust their schedules to accommodate the minimum outputs required by the Generating Units or System Units, if any, to facilitate delivery of Energy from Ancillary Services.

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

**8.8 Black Start.**

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

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

**8.9 [Not Used]**

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

Availability of both contracted and self-provided Ancillary Services shall be verified by the ISO by unannounced testing of Generating Units, Loads and System Resources, by auditing of response to ISO Dispatch instructions, and by analysis of the appropriate Meter Data, or interchange schedules. The ISO may test the capability of any Generating Unit, System Unit, System Resource, external import of a

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

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

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

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

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

**11.2.4.2.2 Allocation of Above-MCP Costs For Accepted Bids.**

For each Settlement Interval, the at or below-MCP costs incurred as a result of accepted bids in the ISO Imbalance Energy Markets shall be allocated in accordance with 11.2.4.1. Allocation of above-MCP

**11.2.10 Payments Under Section 42.1 Contracts.**

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

**11.2.11.1 Obligation for FERC Annual Charges.**

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

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

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

In addition to the surcharges or credits permitted under Sections 11.2.11.3 or 11.6.3.3 of this ISO Tariff, the ISO shall credit or debit, as appropriate, the account of a Scheduling Coordinator for any over- or under-assessment of FERC Annual Charges that the ISO determines occurred due to the error, omission, or miscalculation by the ISO or the Scheduling Coordinator.

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

**11.2.13 Emissions and Start-Up Fuel Cost Charges.**

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

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

**11.2A Auditing**

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

**11.3 Billing and Payment Process.**

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

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

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

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

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

1. Excluding proxy bids, mitigated bids, and bids used out of merit order for managing Intra-Zonal Congestion, the accepted decremental bid, or the lower of the mean or the median of a resource's accepted decremental bids if such a resource has more than one accepted decremental bid in competitive periods over the previous 90 days for peak and off-peak periods, adjusted for daily changes in fuel prices using gas price determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Edison Company, or Pacific Gas and Electric Company), or, if the resource is not served from one of those three Service Areas, from the nearest of those three Service Areas. There will be a six-day time lag between when the gas price used in the daily gas index is determined and when the daily gas index based on that gas price can be calculated. For the purposes of this Section 27.1.1.6.1, to determine whether accepted decremental bids over the previous 90 days were accepted during competitive periods, the independent entity responsible for determining reference prices will apply a test to the prior 90-day period. The test will require that the ratio of a unit's accepted out-of-sequence decremental bids. MWh)

for the prior 90 days to its total accepted decremental bids (MWh) for the prior 90 days be less than 50 percent. If this ratio is greater or equal to 50%, accepted decremental bids will be determined to have been accepted in non-competitive periods and cannot be used to determine the decremental reference price. This test would be applied each day on a rolling 90-day basis. One ratio would be calculated for each unit with no differentiation for various output segments on the unit. Accepted and justified decremental bids below the applicable soft cap, as set forth in Section 39.3 of this Tariff, will be included in the calculation of reference prices;

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

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

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

5. If sufficient data do not exist to calculate a reference level on the basis of the first, second, or fourth methods and the third method is not applicable or an attempt to determine a reference level in consultation with a Market Participant has not been successful, the independent entity responsible for determining reference prices shall determine a reference level on the basis of:

i. the independent entity's estimated costs of an electric facility, taking into account available operating costs data, opportunity cost, and appropriate input from the Market Participant, and the best information available to the independent entity; or incurred for operating the unit at minimum load. The submitted Minimum Load Cost must not be negative and must not exceed the cost-based Minimum Load Cost, as registered in the Master File for the relevant resource. For gas-fired resources, the cost-based Minimum Load Cost shall be derived pursuant to Section 40.8.4.

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

**30.5 [Not Used]**

**30.6 RMR.**

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

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

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

Usage Charge calculated in accordance with Section 27.1.2.

**34 REAL-TIME.**

**34.1 Energy Bids.**

**34.1.1 Energy Bid Definition.**

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

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

**34.1.2 Energy Bid Submission.**

**34.1.2.1 Real Time Market.**

Bids shall be submitted for use in the real-time Hourly Pre-Dispatch Section 34.3.0.2(i) and the Real-Time Economic Dispatch up to sixty-two (62) minutes prior to the Operating Hour. Resources required to offer their Available Generation in accordance with Section 40.7.4 shall be required to submit Energy Bids for 1) all of their Available Generation and 2) any Ancillary Services capacity awarded or self-provided in the Day-Ahead or Hour-Ahead Ancillary Services markets. In the absence of submitted bids, default bids will be used for resources required to offer their Available Generation in accordance with Section 40.7.4. Resources not required to offer their Available Generation in accordance with Section 40.7.4 that were awarded or self-provided Ancillary Services capacity must submit an Energy Bid for no less than the amount of awarded or self-provided Ancillary Services capacity. Resources not required to offer their Available Generation in accordance with Section 40.7.4 may voluntarily submit Energy Bids. Submitted Energy Bids shall be subject to the Damage Control Bid Cap as set forth in Section 39.1 and to the Mitigation Measures set forth in Attachment A to Appendix P.

**34.1.2.2 Real-Time Energy Bid Partition.**

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

**34.1.2.3 Creation of the Real-Time Merit Order Stack.**

**34.1.2.3.1 Sources of Imbalance Energy.**

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

(a) Supplemental Energy Bids;

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

(c) Ancillary Services Energy Bids (except for Regulation) submitted for specific Ancillary Services for those resources which Scheduling Coordinators have elected to use to self-provide such specific Ancillary Services and for which the ISO has accepted such self-provision.

ranges in real time; and

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

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

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

**34.2 Supplemental Energy Bids.**

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

**34.2.1 Identification of Supplemental Energy Bids.**

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

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| | States, Canada or Mexico; however, such entity is not eligible for transmission service that would be prohibited by Section 212(h)(2) of the Federal Power Act; and (ii) any retail customer taking unbundled transmission service pursuant to a state retail access program or pursuant to a voluntary offer of unbundled retail transmission service by the Participating TO. |
| **Eligible Intermittent Resource** | A Generating Unit that is powered solely by 1) wind, 2) solar energy, or 3) hydroelectric potential derived from small conduit water distribution facilities that do not have storage capability. |
| **Emissions Cost Charge** | The charge determined in accordance with Section 40.11. |
| **Emissions Cost Demand** | The level of Demand specified in Section 40.11.3. |
| **Emissions Cost Invoice** | The invoice submitted to the ISO in accordance with Section 40.11.6. |
| **Emissions Cost Trust Account** | The trust account established in accordance with Section 40.11.2. |
| **Emissions Costs** | The mitigation fees, excluding capital costs, assessed against a Generating Unit by a state or federal agency, including air quality districts, for exceeding applicable NOx emissions limitations. |
| **EMS (Energy Management System)** | A computer control system used by electric utility dispatchers to monitor the real-time performance of the various elements of an electric system and to control Generation and transmission facilities. |
| **Encumbrance** | A legal restriction or covenant binding on a Participating TO that affects the operation of any transmission lines or associated facilities and which the ISO needs to take into account in exercising Operational Control over such transmission lines or associated facilities if the Participating TO is not to risk incurring significant liability. Encumbrances shall include Existing Contracts and may include: (1) other legal restrictions or covenants meeting the definition of Encumbrance and arising under other arrangements entered into before the ISO Operations Date, if any; and (2) legal restrictions or covenants meeting the definition of Encumbrance and arising under a contract or other arrangement entered into after the ISO Operations Date. |
| **End-Use Customer or** | A consumer of electric power who consumes such power to satisfy a |

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| | modifications that will be required to provide needed services. |
| **Facility Study Agreement** | An agreement between a Participating TO and either a Market Participant, Project Sponsor, or identified principal beneficiaries pursuant to which the Market Participants, Project Sponsor, and identified principal beneficiaries agree to reimburse the Participating TO for the cost of a Facility Study. |
| **Fed-Wire** | The Federal Reserve Transfer System for electronic funds transfer. |
| **FERC** | The Federal Energy Regulatory Commission or its successor. |
| **FERC Annual Charges** | Those charges assessed against a public utility by the FERC pursuant to 18 C.F.R. § 382.201 and any related statutes or regulations, as they may be amended from time to time. |
| **FERC Annual Charge Recovery Rate** | The rate to be paid by Scheduling Coordinators for recovery of FERC Annual Charges assessed against the ISO for transactions on the ISO Controlled Grid. |
| **FERC Annual Charge Trust Account** | An account to be established by the ISO for the purpose of maintaining funds collected from Scheduling Coordinators for FERC Annual Charges and disbursing such funds to the FERC. |
| **FERC Must-Offer Generator** | All entities defined by Section 40.7.1 of this ISO Tariff. |
| **Final Approval** | A statement of consent by the ISO Control Center to initiate a scheduled Outage. |
| **Final Day-Ahead Schedule** | The Day-Ahead Schedule which has been approved as feasible and consistent with all other Schedules by the ISO based upon the ISO's Day-Ahead Congestion Management procedures. |
| **Final Hour-Ahead Schedule** | The Hour-Ahead Schedule of Generation and Demand that has been approved by the ISO as feasible and consistent with all other Schedules based on the ISO's Hour-Ahead Congestion Management procedures. |
| **Final Invoice** | The invoice due from a RMR Owner to the ISO at termination of the RMR Contract. |
| **Final Schedule** | A Schedule developed by the ISO following receipt of a Revised Schedule from a Scheduling Coordinator. |
| **Final Settlement Statement** | The restatement or recalculation of the Preliminary Settlement Statement by the ISO following the issue of that Preliminary Settlement Statement. |
| **Forbidden Operating** | The operating region of a resource wherein the resource cannot |

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| **ISO Website** | The ISO internet home page at http://www.caiso.com or such other internet address as the ISO shall publish from time to time. |
| **ISP (Internet Service Provider)** | An independent network service organization engaged by the ISO to establish, implement and operate WEnet. |
| **Large Generating Facility** | A Generating Facility having a Generating Facility Capacity of more than 20 MW. |
| **Line Loss Correction Factor** | The line loss correction factor as set forth in the Technical Specifications. |
| **Load** | An end-use device of an End-Use Customer that consumes power. Load should not be confused with Demand, which is the measure of power that a Load receives or requires. |
| **Load-Serving Entity (LSE)** | Any entity (or the duly designated agent of such an entity, including, e.g. a Scheduling Coordinator), including a load aggregator or power marketer; (i) serving End Users within the ISO Control Area and (ii) that has been granted authority or has an obligation pursuant to California State or local law, regulation, or franchise to sell electric energy to End Users located within the ISO Control Area or (iii) is a Federal Power Marketing Authority that serves retail Load. |
| **Load Shedding** | The systematic reduction of system Demand by temporarily decreasing the supply of Energy to Loads in response to transmission system or area capacity shortages, system instability, or voltage control considerations. |
| **Local Furnishing Bond** | Tax-exempt bonds utilized to finance facilities for the local furnishing of electric energy, as described in section 142(f) of the Internal Revenue Code, 26 U.S.C. § 142(f). |
| **Local Furnishing Participating TO** | Any Tax-Exempt Participating TO that owns facilities financed by Local Furnishing Bonds. |
| **Local Publicly Owned Electric Utilities** | A municipality or municipal corporation operating as a public utility furnishing electric service, a municipal utility district furnishing electric service, a public utility district furnishing electric services, an irrigation district furnishing electric services, a state agency or subdivision furnishing electric services, a rural cooperative furnishing electric services, or a joint powers authority that includes one or more of these agencies and that owns Generation or transmission facilities, or furnishes electric services over its own or its members' electric Distribution System. |

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| **Local Regulatory Authority** | The state or local governmental authority responsible for the regulation or oversight of a utility. |
| **Local Reliability Criteria** | Reliability Criteria unique to the transmission systems of each of the PTOs established at the later of: (1) ISO Operations Date, or (2) the date upon which a New Participating TO places its facilities under |

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| **Native Load** | Load required to be served by a utility within its Service Area pursuant to applicable law, franchise, or statute. |
| **NERC** | The North American Electric Reliability Council or its successor. |
| **Net FTR Revenue** | The sum of: 1) the revenue received by the New Participating TO from the sale, auction, or other transfer of the FTRs provided to it pursuant to Section 36.4.3 FTR, or any substantively identical successor provision of the ISO Tariff; and 2) for each hour: a) the Usage Charge revenue received by the New Participating To associated with its Section 36.4.3 FTRs; minus b) Usage Charges that are: i) incurred by the Scheduling Coordinator for the New Participating TO under ISO Tariff Section 27.1.2.1.4 ii) associated with the New Participating TO's Section 36.4.3 FTRs, and iii) incurred by the New Participating TO for its energy transactions but not incurred as a result of the use of the transmission by a third-party and minus c) the charges paid by the New Participating TO pursuant to Section 27.1.2.1.7, to the extent such charges are incurred by the Scheduling Coordinator of the New Participating TO on Congested Inter-Zonal Interfaces that are associated with the Section 36.4.3 FTRs provided to the New Participating TO. The component of New FTR Revenue represented by item 2) immediately above shall not be less than zero for any hour. |
| **Net Negative Uninstructed Deviation** | The real-time change in Generation or Demand associated with underscheduled Load (i.e., Load that appears unscheduled in real time) and overscheduled Generation (i.e., Generation that is scheduled in forward markets and does not appear in real time). Deviations are netted for each Settlement Interval, apply to a Scheduling Coordinator's entire portfolio, and include Load, Generation, imports and exports. |
| **Net Qualifying Capacity** | Qualifying capacity reduced, as applicable, based on: (1) testing and verification; and (2) deliverability restrictions. The Net Qualifying Capacity determination shall be made by the ISO pursuant to the provisions of this ISO Tariff and any applicable manual or procedure. |

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| **Network Upgrades** | The additions, modifications, and upgrades to the ISO Controlled Grid required at or beyond the Point of Interconnection to accommodate the interconnection of the Large Generating Facility to the ISO Controlled Grid. Network |

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| | they were a single Generating Unit and any Generating Unit or Units containing related multiple generating components which meet one or more of the following criteria: i) multiple generating components are related by a common flow of fuel which cannot be interrupted without a substantial loss of efficiency of the combined output of all components; ii) the Energy production from one component necessarily causes Energy production from other components; iii) the operational arrangement of related multiple generating components determines the overall physical efficiency of the combined output of all components; iv) the level of coordination required to schedule individual generating components would cause the ISO to incur scheduling costs far in excess of the benefits of having scheduled such individual components separately; or v) metered output is available only for the combined output of related multiple generating components and separate generating component metering is either impractical or economically inefficient. |
| **Planning Reserve Margin** | A Planning Reserve Margin shall be that quantity or percentage of capacity in MWs that exceeds the Demand Forecast set forth in Section 40.3 as provided for in Section 40.4 of this ISO Tariff. |
| **PMS (Power Management System)** | The ISO computer control system used to monitor the real-time performance of the various elements of the ISO Controlled Grid, control Generation, and perform operational power flow studies. |
| **Point of Change of Ownership** | The point, as set forth in Part A to the Standard Large Generator Interconnection Agreement, where the Interconnection Customer's Interconnection Facilities connect to the Participating TO's Interconnection Facilities. |
| **Point of Interconnection** | The point, as set forth in Part A to the Standard Large Generator Interconnection Agreement, where the Interconnection Facilities connect to the ISO Controlled Grid. |
| **Power Flow Model** | The computer software used by the ISO to model the voltages, power injections and power flows on the ISO Controlled Grid and determine the expected Transmission Losses and Generation Meter Multipliers. |
| **Power System Stabilizers (PSS)** | An electronic control system applied on a Generating Unit that helps to damp out dynamic oscillations on a power system. The |

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| | ISO describing a proposal for the installation of additional Metering Facilities. |
| **Proxy Price** | The value determined for each gas-fired Generating Unit owned or controlled by a Must-Offer Generator in accordance with Section 40.10.1. |
| **PTO Service Territory** | The area in which an IOU, a Local Public Owned Electric Utility, or federal power marketing administration that has turned over its transmission facilities and/or Entitlements to ISO Operational Control is obligated to provided electric service to Load. A PTO Service Territory may be comprised of the Service Areas of more than one Local Public Owned Electric Utility, if they are operating under an agreement with the ISO for aggregation of their MSS and their MSS Operator is designated as the Participating TO. |
| **Queue Position** | The order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the ISO. |
| **Qualifying Capacity** | The maximum capacity of a Resource Adequacy Resource. The criteria for calculating Qualifying Capacity from Resource Adequacy Resources may be established by the CPUC or other applicable Local Regulatory Authority and provided to the ISO, or default provisions in Section 40.13 of this ISO Tariff. |
| **Qualifying Facility** | A qualifying co-generation or small power production facility recognized by FERC. |
| **Ramping** | Changing the loading level of a Generating Unit in a constant manner over a fixed time (e.g., ramping up or ramping down). Such changes may be directed by a computer or manual control. |
| **RAS (Remedial Action Schemes)** | Protective systems that typically utilize a combination of conventional protective relays, computer-based processors, and telecommunications to accomplish rapid, automated response to unplanned power system events. Also, details of RAS logic and any special requirements for arming of RAS schemes, or changes in RAS programming, that may be required. |

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| **Reactive Power Control** | Generation or other equipment needed to maintain acceptable voltage levels on the ISO Controlled Grid and to meet reactive capacity requirements at points of interconnection on the ISO |

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| | voltage or security support of the ISO or a local area. |
| **Reliability Must-Run Unit (RMR Unit)** | A Generating Unit which is the subject of a Reliability Must-Run Contract. |
| **Reliability Network Upgrades** | The transmission facilities at or beyond the Point of Interconnection necessary to interconnect a Large Generating Facility safely and reliably to the ISO Controlled Grid, which would not have been necessary but for the interconnection of the Large Generating Facility, including Network Upgrades necessary to remedy short circuit or stability problems resulting from the interconnection of the Large Generating Facility to the ISO Controlled Grid. Reliability Network Upgrades also include, consistent with WECC practice, the facilities necessary to mitigate any adverse impact the Large Generating Facility's interconnection may have on a path's WECC rating. |
| **Reliability Services Costs** | The costs associated with services provided by the ISO: 1) that are deemed by the ISO as necessary to maintain reliable electric service in the ISO Control Area; and 2) whose costs are billed by the ISO to the Participating TO pursuant to the ISO Tariff. Reliability Services Costs include costs charged by the ISO to a Participating TO associated with service provided under an RMR Contract (Section 30.6.1.2), local out-of-market dispatch calls (Section 11.2.4.2.1) and Minimum Load Costs associated with units committed under the must-offer obligation for local reliability requirements (Section 40.8.6) |
| **REMnet** | The Wide Area Network through which the ISO acquires Meter Data. |
| **Replacement Reserve** | Generating capacity that is dedicated to the ISO, capable of starting up if not already operating, being synchronized to the ISO Controlled Grid, and Ramping to a specified operating level within a sixty (60) minute period, the output of which can be continuously maintained for a two hour period. Also, Curtailable Demand that is capable of being curtailed within sixty minutes and that can remain curtailed for two hours. |

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| **Resource Adequacy** | The program that ensures that adequate physical generating capacity dedicated to serving all load requirements is available to meet peak demand and planning and operating reserves, at or deliverable to locations and at times as may be necessary to ensure local area reliability and system reliability. |
| **Resource Adequacy Capacity** | The capacity of a Resource Adequacy Resource listed on a Resource Adequacy Plan and a Supply Plan. |
| **Resource Adequacy Plan** | A submission by a Scheduling Coordinator for a Load Serving Entity serving Load in the ISO Control Area in order to satisfy the requirements of Section 40 of this ISO Tariff. |
| **Resource Adequacy Resource** | A resource that is required to offer Resource Adequacy Capacity. The criteria for determining the types of resources that are eligible to provide Qualifying Capacity may be established by the CPUC, other applicable Local Regulatory Authority and provided to the ISO, or the default provision in Section 40.13 of this ISO Tariff. |
| **Resource-Specific** | The Resource-Specific Settlement Interval Ex Post Price will |

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| | Interval, over which the ISO settles deviations in Generation and Demand from Final Hour-Ahead Schedules. |
| **Settlement Period** | For all ISO transactions the period beginning at the start of the hour, and ending at the end of the hour. There are twenty-four Settlement Periods in each Trading Day, with the exception of a Trading Day in which there is a change to or from daylight savings time. |
| **Settlement Quality Meter Data** | Meter Data gathered, edited, validated, and stored in a settlement-ready format, for Settlement and auditing purposes. |
| **Settlement Statement** | Either or both of a Preliminary Settlement Statement or Final Settlement Statement. |
| **Settlement Statement Re-run** | The re-calculation of a Settlement Statement in accordance with the provisions of the ISO Tariff. |
| **Settlements, Metering, and Client Relations Charge** | The component of the Grid Management Charge that provides for the recovery of the ISO's costs, including, but not limited to the costs of maintaining customer account data, providing account information to customers, responding to customer inquiries, calculating market charges, resolving customer disputes, and the costs associated with the ISO's Settlement, billing, and metering activities. Because this is a fixed charge per Scheduling Coordinator ID, costs associated with activities listed above also are allocated to other charges under the Grid Management Charge according to formula set forth in Appendix F, Schedule 1, Part A of this Tariff. |
| **Severance Fee** | The charge or periodic charge assessed to customers to recover the reasonable uneconomic portion of costs associated with Generation-related assets and obligations, nuclear decommissioning, and capitalized Energy efficiency investment programs approved prior to August 15, 1996 and as defined in the California Assembly Bill No. 1890 approved by the Governor on September 23, 1996. |
| **Short Start** | Generating Units that that have a cycle time less than five hours (Start-Up Time plus Minimum Run Time is less than five hours) have a Start Up Time less than two hours, and that can be fully optimized with respect to this cycle time. |

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| **Site Control** | Documentation reasonably demonstrating: (1) ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Generating Facility; (2) an option to purchase or acquire a leasehold site for such purpose; or (3) an exclusivity or other business relationship between Interconnection Customer and the entity having the right to sell, lease or grant Interconnection Customer |

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| | costs of High Voltage Transmission Facilities. |
| **Standby Service** | Service provided by a Participating TO that also provides retail electric service, which allows a Standby Service Customer, among other things, access to High Voltage Transmission Facilities for the delivery of backup power on an instantaneous basis to ensure that Energy may be reliably delivered to the Standby Service Customer in the event of an outage of a Generating Unit serving the customer's Load. |
| **Standby Service Customer** | A retail End-Use Customer of a Participating TO that also provides retail electric service that receives Standby Service and pays a Standby Rate. |
| **Standby Transmission Revenue** | The transmission revenues, with respect to cost of both High Voltage Transmission Facilities and Low Voltage Transmission Facilities, collected directly from Standby Service Customers through charges for Standby Service. |
| **Start-Up Cost Charge** | The charge determined in accordance with Section 40.12. |
| **Start-Up Cost Demand** | The level of Demand specified in Section 40.12.3. |
| **Start-Up Cost Invoice** | The invoice submitted to the ISO in accordance with Section 40.12.6. |
| **Start-Up Cost Trust Account** | The trust account established in accordance with Section 40.12.2. |
| **Start-Up Costs** | The cost incurred by a particular Generating Unit from the time of first fire, the time of receipt of an ISO Dispatch instruction, or the time the unit was last synchronized to the grid, whichever is later, until the time the generating unit reaches its minimum operating level. Start-Up Costs are determined as the sum of (1) the cost of auxiliary power used during the start-up and (2) the number that is determined multiplying the actual amount of fuel consumed by the proxy gas price as determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Gas Company, or Pacific Gas and Electric Company), or, if the Must-Offer Generator is not served from one of those three Service Areas, from the nearest of those three Service Areas. |
| **Suggested Adjusted** | The output of the ISO's initial Congestion Management for each |

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| **Schedule** | Scheduling Coordinator for the Day-Ahead Market ("Suggested Adjusted Day-Ahead Schedule") or for the Hour-Ahead Market ("Suggested Adjusted Hour-Ahead Schedule"). These Schedules will reflect ISO suggested adjustments to each Scheduling Coordinator's Preferred Schedule to resolve Inter-Zonal Congestion on the ISO Controlled Grid, based on the Adjustment Bids submitted. These Schedules will be balanced with respect to Generation, Transmission Losses, Load, and trades between Scheduling Coordinators to resolve Inter-Zonal Congestion. |
| **Supplemental Energy** | Energy from Generating Units bound by a Participating Generator Agreement, Loads bound by a Participating Load Agreement, System Units, and System Resources which have uncommitted capacity following finalization of the Hour-Ahead Schedules and for which Scheduling Coordinators have submitted bids to the ISO at least half an hour before the commencement of the Settlement Period. |
| **Supply** | The rate at which Energy is delivered to the ISO Controlled Grid measured in units of watts or standard multiples thereof, e.g., 1,000W=1 KW; 1,000 KW = 1MW, etc. |
| **Supply Plan** | A submission by a Scheduling Coordinator for a Resource Adequacy Resource in order to satisfy the requirements of Section 40 of this ISO Tariff. |
| **System Emergency** | Conditions beyond the normal control of the ISO that affect the ability of the ISO Control Area to function normally including any abnormal system condition which requires immediate manual or automatic action to prevent loss of Load, equipment damage, or tripping of system elements which might result in cascading Outages or to restore system operation to meet the minimum operating reliability criteria. |
| **System Planning Studies** | Reports summarizing studies performed to assess the adequacy of the ISO Controlled Grid as regards conformance to Reliability Criteria. |
| **System Reliability** | A measure of an electric system's ability to deliver uninterrupted service at the proper voltage and frequency. |
| **System Resource** | A group of resources, single resource, or a portion of a resource located outside of the ISO Control Area, or an allocated portion of a Control Area's portfolio of generating resources that are directly responsive to that Control Area's Automatic Generation Control (AGC) capable of providing Energy and/or Ancillary Services to the ISO |

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| **Trading Day** | The twenty-four hour period beginning at the start of the hour ending 0100 and ending at the end of the hour ending 2400 daily, except where there is a change to and from daylight savings time. |
| **Transition Charge** | The component of the Access Charge collected by the ISO with the High Voltage Access Charge in accordance with Section 5.7 of Appendix F, Schedule 3. |
| **Trading Interval** | A Settlement Period as defined in the Master Definitions Supplement of the ISO Tariff. |
| **Transformer Loss Correction Factor** | The transformer loss correction factor as set forth in the Technical Specifications to be applied to revenue quality meters of ISO Metered Entities which are installed on the low voltage side of step-up transformers. |
| **Transition Period** | The period of time established by the California Legislature and CPUC to allow IOUs and Local Publicly Owned Electric Utilities an opportunity to recover Transition Costs or Severance Fees. |
| **Transmission Losses** | Energy that is lost as a natural part of the process of transmitting Energy from Generation to Load delivered at the ISO/UDC boundary or Control Area boundary. |
| **Transmission Ownership Rights** | A non-Participating TO ownership or joint ownership right to transmission facilities within the ISO Control Area that has not executed the Transmission Control Agreement and the transmission facilities are not incorporated into the ISO Controlled Grid. |

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| **Uninstructed Deviation** | A deviation from the resources' Dispatch Operating Point. |
| **Uninstructed Deviation Penalty** | The penalty as set forth in Section 11.2.4.1.2 of this ISO Tariff. |
| **Uninstructed Imbalance Energy** | The real-time change in Generation or Demand other than that instructed by the ISO or which the ISO Tariff provides will be paid at the price for Uninstructed Imbalance Energy. |
| **Unit Commitment** | The process of determining which Generating Units will be committed (started) to meet Demand and provide Ancillary Services in the near future (e.g., the next Trading Day). |
| **Un-Recovered Minimum Load Cost** | The Un-Recovered Minimum Load Cost for each hour of Waiver Denial Period shall be calculated as the difference between: (1) a resource's Minimum Load Costs as calculated in this Section for the same Settlement Interval and (2) the Imbalance Energy payment for a resource's minimum load energy in the Settlement Interval. |
| **Usage Charge** | The amount of money, per 1 kW of scheduled flow, that the ISO charges a Scheduling Coordinator for use of a specific Congested Inter-Zonal Interface during a given hour. |
| **Validation, Estimation and Editing (VEE)** | Applies to Meter Data directly acquired by the ISO. Validation is the process of checking the data to ensure that it is contiguous, within pre-defined limits and has not been flagged by the meter. Estimation and Editing is the process of replacing or making complete Meter Data by using data from redundant meters, schedules, PMS or, if necessary, statistical estimation. |
| **Value Added Network (VAN)** | A data communications service provider that provides, stores and forwards electronic data delivery services within its network and to subscribers on other VANs. The data is mostly EDI type messages. |
| **Voltage Limits** | For all substation busses, the normal and post-contingency Voltage Limits (kV). The bandwidth for normal Voltage Limits must fall within the bandwidth of the post-contingency Voltage Limits. Special voltage limitations for abnormal operating conditions such as heavy or light Demand may be specified. |
| **Voltage Support** | Services provided by Generating Units or other equipment such as shunt capacitors, static var compensators, or synchronous condensers that are required to maintain established grid voltage criteria. This service is required under normal or System Emergency conditions. |

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| **Waiver Denial Period** | The period determined in accordance with Section 40.7.6. |
| **Warning Notice** | A Notice issued by the ISO when the operating requirements for the ISO Controlled Grid are not met in the Hour-Ahead Market, or the quantity of Regulation, Spinning Reserve, Non-Spinning Reserve, |

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

**4.4 Obligations relating to Major Incidents**

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

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

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

## ARTICLE V

## PENALTIES AND SANCTIONS

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

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

**D 2.6.1 Tolerance Band and Performance Check**

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

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

where,

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

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

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

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

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

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

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

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

**D 2.6.2 Unrecovered Costs Neutrality Allocation**

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

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

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

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

**D 2.9 Minimum Load Cost Compensation**

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

**D 3 Meaning of terms in the formulae**

**D 3.1 [Not Used]**

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

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

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

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

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

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

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

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

**D 3.6 [Not Used]**

**D 3.6.1 [Not Used]**

**D 3.6.2 [Not Used]**

**D 3.6.3 [Not Used]**

# ATTACHMENT D

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**4.9.16.2** If the ISO is charging Scheduling Coordinators for summer reliability or demand programs, the MSS Operator may petition the ISO for an exemption of these charges. If the MSS Operator provides documentation to the ISO by November 1 of any year demonstrating that the MSS Operator has secured generating capacity for the following calendar year at least equal to one hundred and fifteen percent (115%), on an annual basis, of the peak Demand responsibility of the MSS Operator, the ISO shall grant the exemption. Eligible generating capacity for such a demonstration may include on-demand rights to Energy, peaking resources, and Demand reduction programs. The peak Demand responsibility of the MSS Operator shall be equal to the annual peak Demand Forecast of the MSS Load plus any firm power sales by the MSS Operator, less interruptible Loads, and less any firm power purchases. Firm power for the purposes of this Section 4.9.16.2 shall be Energy that is intended to be available to the purchaser without being subject to interruption or curtailment by the supplier except for Uncontrollable Forces or emergency. To the extent that the MSS Operator demonstrates that it has secured generating capacity in accordance with this Section 4.9.16.2., the Scheduling Coordinator for the MSS Operator shall not be obligated to bear any share of the ISO's costs for any summer Demand reduction program or for any summer reliability Generation procurement program pursuant to ISO Tariff Section 4~~0.3.1.8~~42.1.8 for the calendar year for which the demonstration is made.

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**8.3.4** The ISO shall procure on a daily and hourly basis, each day, Regulation, Spinning, Non-Spinning and Replacement Reserves. The ISO shall procure Replacement Reserve on a longer-term basis pursuant to Section 4~~0.3.1.3~~42.1.3 if necessary to meet reliability criteria. The ISO Governing Board must approve all long-term Replacement Reserve contracts. The ISO shall contract for Voltage Support annually (or for such other period as the ISO may determine is economically advantageous) and on a daily or hourly basis as required to maintain System Reliability. The ISO shall contract annually (or for such other period as the ISO may determine is economically advantageous) for Black Start Generation.

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## 8.7 Scheduling of Units to Provide Ancillary Services.

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

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

Once the ISO has given Scheduling Coordinators notice of the Day-Ahead and Hour-Ahead Schedules, these schedules represent binding commitments made in the markets between the ISO and the Scheduling Coordinators concerned, subject to any amendments issued as described above. Any minimum energy input and output associated with Regulation and Spinning Reserve services shall be the responsibility of the Scheduling Coordinator, or provided in accordance with the must-offer obligation as set forth in Section ~~40.1~~40.7, as the ISO's auction does not compensate the Scheduling Coordinator for the minimum energy output of Generating Units or System Units, if any, bidding to provide these services.

Accordingly, except as set forth under Section ~~40.1~~40.7, the Scheduling Coordinators shall adjust their schedules to accommodate the minimum outputs required by the Generating Units or System Units, if any, to facilitate delivery of Energy from Ancillary Services.

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

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

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

Start-Up Costs for Condition 2 RMR Units providing service outside the RMR Contract, and any additional Start-Up Cost associated with a Condition 2 RMR Unit providing service under the RMR Contract when the unit's total service has exceeded an RMR Contract Service Limit but neither the RMR Contract

Counted MWh, Counted Service Hours or Counted Start-ups have exceeded the applicable RMR Contract Service Limit, shall be invoiced in accordance with Section ~~40.1.10.6~~40.12.6 and collected in accordance with Section ~~40.1.10.1~~40.12.1.

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**11.2.10 Payments Under Section ~~40.3.1~~42.1 Contracts.**

The ISO shall calculate and levy charges for the recovery of costs incurred under contracts entered into by the ISO under the authority granted in Section ~~40.3.1~~42.1 in accordance with Section ~~40.3.1.8~~42.1.8 of this ISO Tariff.

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**11.2.13 Emissions and Start-Up Fuel Cost Charges.**

The ISO shall calculate, account for and settle charges and payments for Emissions Costs and Start-Up Fuel Costs in accordance with Sections ~~40.1.9~~40.11 and ~~40.1.10~~40.12 of this ISO Tariff.

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**27.1.1.6.1 Decremental Bids.**

With regard to decremental bids, if Final Hour-Ahead Schedules cause Congestion on the Intra-Zonal interface, the ISO shall, after Dispatching available and effective Reliability Must-Run Units to manage the Congestion, apply the decremental reference prices determined by the independent entity that determines the reference prices for the Automatic Mitigation Procedure (AMP) as described in Appendix P, Attachment A. The ISO shall Dispatch Generating Units according to the decremental reference prices thus established, the resource's effectiveness on the Congestion, and other relevant factors such as Energy limitations, existing contractual restrictions, and Regulatory Must-Run or Regulatory Must-Take status, to alleviate the Congestion after Final Hour-Ahead Schedules are issued. Where the ISO must reduce a Generating Unit's output, the ISO shall Dispatch Generating Units according to the decremental reference prices and not according to Adjustment Bids or Supplemental Energy Bids to alleviate Intra-

Zonal Congestion. No Generating Unit shall be Dispatched below its minimum operating level or above its maximum operating level. No Reliability Must-Run Unit shall be Dispatched below the operating level determined by the ISO as necessary to maintain reliability. If Congestion still exists after all Generating Units are Dispatched to their minimum operating levels, the ISO shall instruct Generating Units to shut off in merit order based on their total shut-down costs, beginning with the most expensive unit, where such shut-down costs include the lesser of the cost to start up the Generating Unit or to keep the Generating Unit warm for each Generating Unit with a non-zero Final Day-Ahead Schedule for Energy for the next day. Units shut off due to Congestion as set forth in this Section 27.1.1.6.1 shall be charged the lesser of the decremental reference price for the operating range between zero MW output and the unit's minimum operating level or the relevant Market Clearing Price.

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

The ISO shall apply the decremental reference prices to thermal Generating Units and to non-thermal Generating Units. If a Generating Unit is instructed by the ISO to shut down to manage Intra-Zonal Congestion, and is subsequently re-started, the Owner of that Generating Unit may invoice the ISO for the lesser of (1) the Start-Up Costs incurred and (2) the costs of keeping the Generating Unit warm to meet its Energy Schedules as set forth in Section ~~40.1.10.6~~40.12.6. If the ISO Dispatches System Resources or Dispatchable Loads to alleviate Intra-Zonal Congestion, the ISO shall Dispatch those resources in merit order according to the resource's Day-Ahead or Hour-Ahead Adjustment Bid or Imbalance Energy bid.

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

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

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

1. Excluding proxy bids, mitigated bids, and bids used out of merit order for managing Intra-Zonal Congestion, the accepted decremental bid, or the lower of the mean or the median of a resource's accepted decremental bids if such a resource has more than one accepted decremental bid in competitive periods over the previous 90 days for peak and off-peak periods, adjusted for daily changes in fuel prices using gas price determined by Equation C1-8 (Gas) of the Schedules to the Reliability Must-Run Contract for the relevant Service Area (San Diego Gas & Electric Company, Southern California Edison Company, or Pacific Gas and Electric Company), or, if the resource is not served from one of those three Service Areas, from the nearest of those three Service Areas. There will be a six-day time lag between when the gas price used in the daily gas index is determined and when the daily gas index based on that gas price can be calculated. For the purposes of this Section 27.1.1.6.1, to determine whether accepted decremental bids over the previous 90 days were accepted during competitive periods, the independent entity responsible for determining reference prices will apply a test to the prior 90-day period. The test will require that the ratio of a unit's accepted out-of-sequence decremental bids. MWh) for the prior 90 days to its total accepted decremental bids (MWh) for the prior 90 days be less than 50 percent. If this ratio is greater or equal to 50%, accepted decremental bids will be determined to have been accepted in non-competitive periods and cannot be used to determine the decremental reference price. This test would be applied each day on a rolling 90-day basis. One ratio would be calculated for each unit with no differentiation for various output segments on the unit. Accepted and justified decremental bids below the applicable soft cap, as set forth in Section 39.3 of this Tariff, will be included

in the calculation of reference prices;

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

3. 90 percent of the unit's default Energy Bid determined monthly as set forth in Section ~~40.1.5~~40.7.5 (based on the incremental heat rate submitted to the independent entity responsible for determining reference prices, adjusted for gas prices, determined according to paragraph (a)(1) above, and the variable O&M cost on file with the independent entity responsible for determining reference prices, or the default O&M cost of $6/MWh);

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

5. If sufficient data do not exist to calculate a reference level on the basis of the first, second, or fourth methods and the third method is not applicable or an attempt to determine a reference level in consultation with a Market Participant has not been successful, the independent entity responsible for determining reference prices shall determine a reference level on the basis of:

i. the independent entity's estimated costs of an electric facility, taking into account available operating costs data, opportunity cost, and appropriate input from the Market Participant, and the best information available to the independent entity; or

ii. an appropriate average of competitive bids of one or more similar electric Facilities.

(b) Monotonicity. The decremental bid reference levels ($/MWh bid price) for the different bid segments of each resource shall be made monotonically non-decreasing by the independent entity responsible for determining reference prices by proceeding from the highest MW bid segment moving through each lower MW bid segment. The reference level of each succeeding bid segment, moving from right to left in order of decreasing operating level, shall be the lower of the reference level of the preceding bid segment or the reference level determined according to paragraph (a) above.

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### 30.4.9 Format and Validation of Minimum Load Costs.

For a Generating Unit, the submitted Minimum Load Cost expressed in dollars per hour ($/hr) is the cost incurred for operating the unit at minimum load. The submitted Minimum Load Cost must not be negative and must not exceed the cost-based Minimum Load Cost, as registered in the

Master File for the relevant resource. For gas-fired resources, the cost-based Minimum Load Cost shall be derived pursuant to Section ~~40.1.6.1.2~~40.8.4.

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

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### 34.1.2.1 Real Time Market.

Bids shall be submitted for use in the real-time Hourly Pre-Dispatch Section 34.3.0.2(i) and the Real-Time Economic Dispatch up to sixty-two (62) minutes prior to the Operating Hour. Resources required to offer their Available Generation in accordance with Section ~~40.1.4~~40.7.4 shall be required to submit Energy Bids for 1) all of their Available Generation and 2) any Ancillary Services capacity awarded or self-provided in the Day-Ahead or Hour-Ahead Ancillary Services markets. In the absence of submitted bids, default bids will be used for resources required to offer their Available Generation in accordance with Section ~~40.1.4~~40.7.4. Resources not required to offer their Available Generation in accordance with Section ~~40.1.4~~40.7.4 that were awarded or self-provided Ancillary Services capacity must submit an Energy Bid for no less than the amount of awarded or self-provided Ancillary Services capacity. Resources not required to offer their Available Generation in accordance with Section ~~40.1.4~~40.7.4 may voluntarily submit Energy Bids. Submitted Energy Bids shall be subject to the Damage Control Bid Cap as set forth in Section 39.1 and to the Mitigation Measures set forth in Attachment A to Appendix P.

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

Scheduling Coordinators for resources that have been awarded or self-provide Regulation Up, Spinning Reserve, Non-Spinning Reserve or Replacement Reserve capacity must submit a Supplemental Energy bid for at least all the awarded or self-provided Ancillary Services capacity. To the extent a Supplemental Energy bid is not so submitted for a gas-fired resource, the ISO shall calculate a Supplemental Energy bid in accordance with Section ~~40.1.8~~40.10.1 and insert that bid into the real-time Imbalance Energy market. To the extent a Supplemental Energy bid is not so submitted for a non-gas-fired resource, the ISO shall insert a bid of $0/MWh into the real-time Imbalance Energy market.

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| **Emissions Cost Charge** | The charge determined in accordance with Section ~~40.1.9~~40.11. |
| **Emissions Cost Demand** | The level of Demand specified in Section ~~40.1.9.3~~40.11.3. |
| **Emissions Cost Invoice** | The invoice submitted to the ISO in accordance with Section ~~40.1.9.6~~40.11.6. |
| **Emissions Cost Trust Account** | The trust account established in accordance with Section ~~40.1.9.2~~40.11.2. |

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| **FERC Must-Offer Generator** | All entities defined ~~in~~by Section ~~40.1.1~~40.7.1 of ~~the~~this ISO Tariff. |

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| **ISO Website** | The ISO internet home page at http://www.caiso.com or such other |

internet address as the ISO shall publish from time to time.

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| **Load-Serving Entity (LSE)** | Any entity (or the duly designated agent of such an entity, including, e.g. a Scheduling Coordinator), including a load aggregator or power marketer; (i) serving End Users within the ISO Control Area and (ii) that has been granted authority or has an obligation pursuant to California State or local law, regulation, or franchise to sell electric energy to End Users located within the ISO Control Area or (iii) is a Federal Power Marketing Authority that serves retail Load. |

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| **~~Must-Offer Generator~~** | ~~All entities defined in Section 40.1.1 of the ISO Tariff~~ |

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| **Net Qualifying Capacity** | Qualifying capacity reduced, as applicable, based on: (1) testing and verification; and (2) deliverability restrictions. The Net Qualifying Capacity determination shall be made by the ISO pursuant to the provisions of this ISO Tariff and any applicable manual or procedure. |

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| **Planning Reserve Margin** | A Planning Reserve Margin shall be that quantity or percentage of capacity in MWs that exceeds the Demand Forecast set forth in Section 40.3 as provided for in Section 40.4 of this ISO Tariff. |

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| **Proxy Price** | The value determined for each gas-fired Generating Unit owned or controlled by a Must-Offer Generator in accordance with Section ~~40.1.8~~40.10.1. |

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**Qualifying Capacity** — The maximum capacity of a Resource Adequacy Resource. The criteria for calculating Qualifying Capacity from Resource Adequacy Resources may be established by the CPUC or other applicable Local Regulatory Authority and provided to the ISO, or default provisions in Section 40.13 of this ISO Tariff.

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**Reliability Services Costs** — The costs associated with services provided by the ISO: 1) that are deemed by the ISO as necessary to maintain reliable electric service in the ISO Control Area; and 2) whose costs are billed by the ISO to the Participating TO pursuant to the ISO Tariff. Reliability Services Costs include costs charged by the ISO to a Participating TO associated with service provided under an RMR Contract (Section 30.6.1.2), local out-of-market dispatch calls (Section 11.2.4.2.1) and Minimum Load Costs associated with units committed under the must-offer obligation for local reliability requirements (Section ~~40.1.6.1.4~~40.8.6)

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**Resource Adequacy** — The program that ensures that adequate physical generating capacity dedicated to serving all load requirements is available to meet peak demand and planning and operating reserves, at or deliverable to locations and at times as may be necessary to ensure local area reliability and system reliability.

**Resource Adequacy Capacity** — The capacity of a Resource Adequacy Resource listed on a Resource Adequacy Plan and a Supply Plan.

**Resource Adequacy Plan** — A submission by a Scheduling Coordinator for a Load Serving Entity serving Load in the ISO Control Area in order to satisfy the requirements of Section 40 of this ISO Tariff.

**Resource Adequacy Resource** — A resource that is required to offer Resource Adequacy Capacity. The criteria for determining the types of resources that are eligible to provide Qualifying Capacity may be established by the CPUC, other applicable Local Regulatory

Authority and provided to the ISO, or the default provision in Section 40.13 of this ISO Tariff.

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| **Short Start** | Generating Units that that have a cycle time less than five hours (Start-Up Time plus Minimum Run Time is less than five hours) have a Start Up Time less than two hours, and that can be fully optimized with respect to this cycle time. |

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| **Start-Up Cost Charge** | The charge determined in accordance with Section ~~40.1.10~~40.12. |
| **Start-Up Cost Demand** | The level of Demand specified in Section ~~40.1.10.3~~40.12.3. |
| **Start-Up Cost Invoice** | The invoice submitted to the ISO in accordance with Section ~~40.1.10.6~~40.12.6. |
| **Start-Up Cost Trust Account** | The trust account established in accordance with Section ~~40.1.10.2~~40.12.2. |

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| **Supply Plan** | A submission by a Scheduling Coordinator for a Resource Adequacy Resource in order to satisfy the requirements of Section 40 of this ISO Tariff. |

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| **Transmission Ownership Rights** | A non-Participating TO ownership or joint ownership right to transmission facilities within the ISO Control Area that has not executed the Transmission Control Agreement and the transmission facilities are not incorporated into the ISO Controlled Grid. |

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| **Un-Recovered Minimum Load Cost** | The Un-Recovered Minimum Load Cost for each hour of Waiver Denial Period shall be calculated as the difference between: (1) a resource's Minimum Load Costs as calculated in this Section for the same Settlement Interval and (2) the Imbalance Energy payment for a |

resource's minimum load energy in the Settlement Interval.

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**Waiver Denial Period** The period determined in accordance with Section ~~40.1.6~~40.7.6.

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**[Appendix B.3]**

4.5 **Dispatch and Curtailment.** The ISO shall only dispatch or curtail a Net Scheduled QF of the Participating Generator: (a) to the extent the Participating Generator bids Energy or Ancillary Services from the Net Scheduled QF into the ISO's markets or the Energy is otherwise available to the ISO under Section ~~40.1.4~~40.7.4 of the ISO Tariff; or (b) if the ISO must dispatch or curtail the Net Scheduled QF in order to respond to an existing or imminent System Emergency or condition that would compromise ISO Control Area integrity or reliability as provided in Sections 7, 7.3.1, and 11.2.4.2.1 of the ISO Tariff.

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**[Appendix N]**

**D 2.6.1 Tolerance Band and Performance Check**

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

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

where,

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

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

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

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

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

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

Must-offer resources that produce a quantity of Energy above Minimum Load due to an ISO Dispatch Instruction during a Waiver Denial Period are not subject to the Tolerance Band requirement for purposes of receiving Minimum Load Cost Compensation, as defined in Section ~~40.1.6.1~~40.8. Accordingly, the $PERF\_STAT_{i,h,o}$ for eligible must-offer resources, as defined in Section ~~40.1.6.1~~40.8, shall be set to 1, irrespective of deviations outside of the Tolerance Band, for the purpose of determining eligibility for Minimum Load Cost Compensation during a Waiver Denial Period. The Tolerance Band shall be used to apply UDP during a Waiver Denial Period.

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

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**[Appendix N]**

**D 2.9 Minimum Load Cost Compensation**

The ISO shall calculate a Must-Offer Generator's Minimum Load Cost Compensation (MLCC), pursuant to section ~~40.1.6.1.1~~40.8.1 of the ISO Tariff, as the Minimum Load Cost for each resource *i* during Settlement Interval *o* of hour *h*, as defined in section ~~40.1.6.1.2~~40.8.4 of the ISO Tariff.

# ATTACHMENT E

# INDEX

ATTACHMENT F

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## ATTACHMENT G

# Memorandum

**To:** ISO Board of Governors

**From:** Phil Pettingill, Manager, Infrastructure Policy and Contracts

**cc:** ISO Officers

**Date:** March 2, 2006

***Re:*** ***Approval of Pre-MRTU Reliability Requirements Issues for March 2006 Tariff Filing***

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***This memorandum requires Board action.***

## EXECUTIVE SUMMARY

Management recommends Board approval of the Pre-Market Redesign and Technology Update ("Pre-MRTU") Reliability Requirements tariff ("RR") policy elements summarized in this memorandum. These policy and design features are intended to complement the State's efforts to implement resource adequacy ("RA") programs and, in particular, the California Public Utilities Commission's commitment to implement RA on June 1, 2006. Accordingly, the ISO intends for the Pre-MRTU RR Tariff provisions to be effective by June 1, 2006 and endure solely for the interim period prior to implementation of Phase 1 of MRTU.[1] Tariff provisions to replace the Pre-MRTU RR Tariff elements were filed with the Federal Energy Regulatory Commission ("FERC") as part of the February 9, 2006, MRTU Tariff filing.

These Pre-MRTU RR policy and design features have undergone public review. Many elements have been modified in direct response to stakeholder concerns. A summary of the stakeholder issues and how they were addressed is provided in a matrix as Appendix A. Thus, Management is requesting the Board approve the policy elements described in this memo and further authorize Management to make the appropriate tariff filings in a timely manner.

The remainder of this memo contains a discussion of the policy and design features and recommendations as they pertain to these essential categories:

- Discussion of availability obligations, including continued backstop reliance on a modified FERC must-offer obligation ("FERC MOO"), imposed on resources to meet reliability criteria ("RR MOO");
- Discussion of changes to settlement treatment for RR resources committed pursuant to the RR MOO; and

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[1] Given that the ISO has been assigned certain activities that must be conducted prior to the June 1, 2006 implementation date for the CPUC's RA program, such as obtaining month-ahead RA showing from resources, the ISO is planning to have the Pre-MRTU RR Tariff language submitted to FERC on March 10, 2006. Under the Federal Power Act, FERC has sixty (60) days to review an amendment to a tariff.

- Relationship of Pre-MRTU RR tariff to the California Public Utilities Commission ("CPUC") and Local Regulatory Authorities ("LRA")
- Discussion of deliverability requirements

**BACKGROUND**

The Pre-MRTU RR Tariff is intended to compliment the State's efforts to implement RA programs. The long-term objectives of RA are to (1) ensure adequate resource capacity is available to reliably meet forecast demand and reserves when and where it is needed, (2) encourage investments required to ensure that reliability actually occurs, and (3) spur Load Serving Entities ("LSEs") to take on the primary procurement role to ensure sufficient capacity is available.[2] The Pre-MRTU RR Tariff facilitates realization of these objectives for RA by coordinating how RA and other resources are made available to the ISO in the operational time frame to ensure load may be reliably served. As noted above, the ISO is seeking approval of the design and policy features of the Pre-MRTU RR Tariff language at this time to ensure RA integration with the existing market design by June 1, 2006, which is the RA implementation date established by the CPUC.

At its November 21, 2002 meeting, the ISO Board of Governors directed ISO management to defer to State efforts to address the broader issue of RA. In addition, the Board directed management to actively engage in the CPUC proceeding regarding the establishment of procurement rules for the State's Investor Owned Utilities. At that meeting, the Board acknowledged the State's legitimate and primary role in addressing matters related to RA or, more specifically, the obligations of LSEs to procure enough resources to serve their Load plus reserves.

Primarily through three significant decisions, the CPUC has adopted an RA framework intended to provide sufficient incentives for the development of new electric infrastructure investment, and maintenance of necessary existing Generation, by mandating that entities that serve electric customers secure sufficient resources of their own or through contracts to meet their customers' needs. These RA contracts are expected to provide a revenue stream to contribute to the fixed costs of Generation owners and enable new projects to secure the financing they need for construction. In particular, in Decisions ("D.") 04-01-50 and 04-10-035, the CPUC required LSEs under its jurisdiction to demonstrate that they have acquired the capacity needed to serve their forecasted retail customer load and a 15-17% reserve margin. D.04-10-035 adopted various load forecast and resource counting conventions to assess LSE compliance, imposed a monthly reporting requirement in additional to an annual showing, and, importantly, accelerated the implementation of RA to June 2006. D.05-10-042 refined the procedures for implementing RA, but deferred adoption of any local capacity requirements for further consideration for potential implementation in 2007. In addition to the efforts initiated by the CPUC, the California legislature enacted A.B. 380, which directed the CPUC to establish, in consultation with the ISO, RA requirements for LSEs under its jurisdiction. A.B. 380 further required each locally owned public electric utility to plan for and procure sufficient resources to meet its planning reserve margin and peak demand and operating reserves.

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2 California Assembly Bill 380 defines RA as a regulatory structure which "*ensures that adequate physical generating capacity dedicated to serving all load requirements is available to meet peak demand and planning and operating reserves, at or deliverable to locations and at times as may be necessary to ensure local area reliability and system reliability, at just and reasonable rates.*"

## STAKEHOLDER PROCESS

Since March 2005, the ISO has conducted monthly forums with stakeholders describing the RA elements associated with the MRTU Tariff filing. The RA-focused portion of the MRTU stakeholder effort included two full days of face-to-face stakeholder meetings, five formal rounds of stakeholder written comments and numerous iterations of White Papers proposals that have shaped the development of policies to integrate the ISO Tariff with RA requirements. With this information as a foundation, in early 2006 the ISO initiated a separate stakeholder process for development of the RR Tariff. The RR Tariff stakeholder process has included the following milestones:

- Feb 3 Draft RR Tariff posted
- Feb 14 Stakeholder meeting
- Feb 21 Stakeholder written comments due
- Mar 2 Stakeholder conference call
- Mar 6 Summarize ISO response to stakeholder inputs
- Mar 8-9 Request approval from Board of Governors

Stakeholder participation has been extensive and extremely helpful. Management recognizes that some stakeholders remain concerned with certain features but management believes that in each case the ISO's proposed resolution is reasonable, fair and workable. In some cases, the ISO's position was driven by its view of the best approach to assure reliable, efficient markets. In other cases where equity was the primary consideration, the ISO sought to achieve a balanced approach based on the stated participant interests. A matrix of issues that includes previously expressed stakeholder positions and the ISO responses is detailed in Attachment A.

## PRE--MRTU RR ISSUES RESOLUTION

This section provides a summary description of the RR issues that have been resolved within this stakeholder process.

General Principles and Structure of the Pre-MRTU RR Tariff

Four interdependent, practical considerations guided the development of the Pre-MRTU RR Tariff.

First, while respecting the primary role of the CPUC and other Local Regulatory Authorities ("LRAs") in the area of long-term supply planning and procurement, as recognized by the ISO Board, the ISO remains statutorily obligated to operate the ISO Controlled Grid in accordance with Applicable Reliability Criteria and Good Utility Practice. To accomplish this requirement, the ISO must have sufficient resources in appropriate locations to meet Demand. Moreover, the efforts of State regulatory entities to ensure that LSEs secure sufficient resources can only achieve the intended reliability benefits if the procurement rules are integrated with the design of the ISO Markets and bidding practices as well as the physical realities of the ISO Controlled Grid.

Second, the design features of this portion of the ISO Tariff must be implementable on an expedited schedule to meet the CPUC's June 1, 2006 RA deadline.

Third, the design features would be temporary, intended only to be effective until implementation of MRTU in November 2007. As such, ISO management did not believe it was prudent to expend substantial time and resources of both the ISO and Market Participants for an interim 18-month period.

Fourth, RA at the state level remains evolutionary and transitional in that many of the resources meeting the current RA requirements were entered into in the past without contemplation of RA obligations. Thus, certain supply arrangements, most notably the use of firm energy contracts that are frequently referred to as liquidated damage contracts, do not comport with an effective RA program based on physical obligations.

These four considerations led to the general principle that the Pre-MRTU RR Tariff should be designed with an intent to minimize system changes at the ISO, which requires reliance upon existing processes, procedures, and tariff authority to the maximum extent possible, while still looking ahead to a well functioning RA program under MRTU. Accordingly, a feature of the Pre-MRTU RR Tariff is its continued reliance for this interim period on the FERC MOO, the associated Must Offer Waiver Denial ("MOWD") process and procedures, and the Minimum Load Cost Compensation ("MLCC") provisions to make resources available for commitment to meet ISO reliability needs. However, the FERC MOO has been modified to be a backstop to resources secured by Scheduling Coordinators for Load Serving Entities ("LSE") under the new RA program. Thus, a primary modification includes revising the MOWD process to deny waivers first to those resources that have received an RA capacity payment, i.e., the ISO will to the extent operationally practical run the system without calling on units under the FERC-MOO. Instead, the ISO will issue a MOWD to RA resources prior to issuing MOWD to non-RA resources under the FERC MOO [3]

The existing ISO tariff has also been modified to reflect the reality that a resource designated by an LSE as a RA resource has received a bilateral payment to make its capacity available to the ISO. To prevent double payment, the ISO proposes to revise the MLCC to recognize that RA resources have received an explicit capacity payment and therefore no longer require the implicit capacity payment embodied in the current MLCC provisions.

These major Pre-MRTU RR issues as well as the recognition of the supporting role of the ISO to the CPUC and LRAs in implementing RA are discussed in further detail below.

<u>Must-Offer Obligation</u>

As noted, the FERC MOO provisions that are currently in the ISO Tariff have been largely preserved in the Pre-MRTU RR Tariff language. The FERC MOO will remain in place to ensure that the ISO can meet system, zonal and local reliability needs. In part, the need to retain the FERC MOO arises from the absence of a final decision by the CPUC imposing Local Capacity Obligations on its jurisdictional LSEs, continued counting of non-resource specific energy contracts such as Firm liquated Damage contracts and the present absence of a viable ISO "backstop" procurement process[4]. It is anticipated that the Pre-MRTU RR Tariff may need to be modified later in 2006 to incorporate the outcome of the CPUC's pending proceeding to determine local capacity requirements for 2007. Without a Local Capacity Requirement, and the operational need to address zonal requirements, the ISO must continue to have a mechanism to address the system conditions that the ISO is currently using the FERC MOO to address. It is generally presumed that the planning reserve margin imposed on LSEs will ensure that sufficient resources exist to address "system" conditions. Hence, ISO management has determined a need to maintain the FERC

[3] Resource operating constraints in must be taken into consideration.

[4] On a separate effort the ISO is continuing work with parties to resolve a compliant filed by IEP regarding the existing Must-Offer Obligation **EL05-146-000**.

MOO, at least until such time as an alternate mechanism such as a Reliability Capacity Services Tariff, or similar mechanism, is in place.

A key modification to current tariff language is the change in priority for MOWDs. The ISO will continue to use the existing MOWD process, i.e., day-ahead commitment notification, but the ISO will commit RA resources (resources included in LSEs' RA resource showings) before committing the FERC MOO resources. This change is justified by the fact that LSEs have already paid for the RA resources to be made available to the ISO.

The scope of the resources subject to MOO is driven by existing ISO system capabilities and practicality. Again, to minimize system changes, the Pre-MRTU RR Tariff mirrors the type of resources that currently exist and are subject to FERC MOO, except that System Resources, i.e., imports, procured and counted by CPUC jurisdictional LSEs after the date October 27, 2005 must be available to the ISO in accordance with the CPUC directive. Accordingly, the ISO Tariff will be modified to require RA imports to submit Supplemental Energy bids in its RT market for contractual RA capacity not already scheduled by the LSE in the Day-Ahead or Hour-Ahead market to the extent required by the CPUC or LRA to meet RA offer standards[5]. Finally, the ISO recognizes there may be some contracts that existed prior to the CPUC RA decision or have different obligations adopted by an LRA other than the CPUC. Thus, it is appropriate that such resources have a real-time offer obligation consistent with that adopted by the LRA and/or the provisions of an existing contract

In developing tariff language, the ISO initially considered expanding the scope of the RA MOO to thermal resources in the ISO Control Area that are owned or controlled by Metered Subsystem ("MSS") Operators. After receiving stakeholder comments, the ISO now views that the MSS agreements preclude this approach, yet ensure that MSS resources will be made available to the ISO in situations of an actual or imminent emergency. The filed Pre-MRTU RR Tariff language will exclude all MSSs from the scope of the MOO (both load following and non-load following MSSs).

In addition, as under the current tariff, hydroelectric, regulatory must-take, and non-dispatchable resources like Qualifying Facilities are exempt from the MOO. These resources are exempt because it is not practical to change the ISO systems to implement a new regime for the interim 18-month period prior to MRTU. However, these resources are expected to schedule in the Day-Ahead market at a level consistent with their expected deliveries for the next Trade-Day.

<u>Changes to Settlement</u>

Under the existing Must-Offer rules approved by the FERC, a resource that is denied a Must-Offer Waiver shall be compensated for its minimum load costs in addition to receiving payment for the imbalance energy that is produced when operating at its minimum load. In the past, some parties have identified this practice as a "double payment". However, FERC has maintained that this compensation method for minimum load costs is an appropriate proxy for a capacity payment until a resource is able to earn a capacity payment through another mechanism such as a Resource Adequacy contract. Now that resources have the opportunity to enter into an RA contract and

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[5] The ISO is not in a position to insert proxy bids in the case where system resources do not schedule in the Day-Ahead market and do not offer into the real-time imbalance energy market. This limitation exists partly because of systems limitations but is due in most part because these resources are not linked to a physical resource with characteristics such as heat rate, fuel type, etc

LSEs have an obligation to seek such agreements, it is appropriate to modify the minimum load cost compensation methodology for such contracted resources. The ISO proposes to ensure that such resources are not paid less than their minimum load costs after considering the compensation from the imbalance energy market. For example: a RA resource will only be paid a MLCC uplift payment to the extent the imbalance energy payment is insufficient to allow the resource to recover its minimum load costs. Conversely, the existing minimum load cost compensation method will be maintained for resources that are not under an RA contract.

Deliverability

Deliverability encompasses the concept that a resource relied upon to serve load can actually do so. The ISO has consistently argued that an effective RA program needs to fully consider the deliverability of resources. The CPUC concurred in D.04-10-035 (October 2004) when it recognized that the objectives of RA would be undercut by a failure to impose deliverability requirements.

Therefore, the proposed tariff amendments will implement provisions for the deliverability of generation to the aggregate of load and the deliverability of imports to the ISO control area. The deliverability of generation to the aggregate of load measures the impact of the transmission system and the dispatch of other proximate generation resources on the ability of a particular generator to provide energy to the ISO transmission system at peak load. A resource whose output is subject to a transmission constraint under the study criteria is not fully deliverable and the capacity that it may offer for RA purposes would be reduced. The ISO will update this analysis on an annual basis.

The screen to assess the deliverability of imports identifies the megawatt amount that should be considered deliverable from outside the ISO Controlled Grid through import paths. This quantity of import capacity is then allocated to the respective LRAs for allocation between its jurisdictional entities. As stated above, this tariff is transitional as is the current construct of RA in California. Therefore, as deliverability is still being refined, some parties have raised concerns about the allocation of import capacity. The proposed tariff language will allocate available import capacity equally to parties that enter into new import contracts. The ISO is also concerned about the appropriate incentives for long-term RA procurement. Thus, it is committed to continue working with stakeholders and LRAs to establish appropriate allocation methods that support and encourage long-term investment in infrastructure.

Deference to Applicable LRA and Compliance

In accordance with direction from the Board in 2002 and AB 380, the ISO has acknowledged the primary role of the CPUC and LRAs in determining long-term procurement policies for LSEs under their jurisdiction. Deference is demonstrated by the proposed tariff by incorporating the following RA rules developed by the CPUC or LRA:

- Load forecast and protocols
- Planning reserve margin
- Resource counting conventions
- Penalties for failure to comply with planning reserve margin requirements.

The initial draft of the tariff language attempted to create consistency among the myriad of LSEs by imposing minimum standards that would be applicable to all LSEs. However, after considering stakeholder comments, to ensure comparability between CPUC and non-CPUC jurisdictional entities, the ISO has uniformly elected to defer to the state regulatory entities.

With respect to those areas in which the ISO defers to the CPUC or LRA, the Pre-MRTU RR Tariff serves to (1) implement rules adopted by the CPUC and LRAs, including providing technical input and (2) implement rules over suppliers outside the jurisdiction of the CPUC or LRA. In this regard, the proposed tariff requires a showing from the SC for the LSE and a confirmatory showing from the SC for the resource that will be supplying the capacity. The LSE showing, while a requirement imposed by the CPUC, is necessary for the ISO in order to identify those resources that should be subject to the revised MOWD process and MLCC settlement provisions and therefore has been made a part of the tariff.

<u>Other Activities Whose Outcomes could affect these Resolutions</u>

The policy issues discussed in this memorandum should complete the design and resolve overriding policy issues that establish the foundation of this market design element. Nevertheless, there are other activities in progress at this time whose outcomes can affect the resolutions proposed here and could require the ISO to make adjustments to the filing at a later date. These other activities include: (1) settlement discussion on the Reliability Capacity Services Tariff (RCST) proceeding at FERC; and (2) anticipated CPUC orders in mid-2006 on local capacity requirements. If these activities impact the current design, the ISO will initiate a stakeholder process to examine any modifications.

A brief summary of the RCST settlement discussions begins with August 26, 2005, when the Independent Energy Producers (IEP) filed a complaint to remove the existing FERC Must Offer Obligation. Then, FERC held a technical conference on November 8 and 9, 2005. Today, the Settlement discussions among the parties are ongoing. Until RCST is resolved, the draft RR Tariff relies upon the continuance of the FERC MOO. If the parties can reach agreement on the RCST, then the ISO will revise the 2006 Tariff accordingly.

## CONCLUSION AND MANAGEMENT RECOMMENDATION

Management recommends that the Board approve the policies summarized above. Management recommends the following motion.

**MOVED,**

**That the ISO Board of Governors approves the Pre-MRTU Reliability Requirements policy proposals, as outlined in this memorandum dated February 28, 2006, and related attachments.**

**Further,**

**That the Board of Governors authorizes management to file the necessary tariff provisions to implement the Pre-MRTU Reliability Requirements.**

# Memorandum

**To:** ISO Board of Governors

**From:** Phil Pettingill, Manager, Infrastructure Policy and Contracts

**cc:** ISO Officers

**Date:** March 9, 2009

***Re:*** ***Addendum to Approval of Pre-MRTU Reliability Requirements Issues for March 2006 Tariff Filing***

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## MODIFICATION TO IMPORT CAPACITY ALLOCATION

Page 7 of the March 2, 2006 "Memorandum re Approval of Pre-MRTU Reliability Requirements Issues for March 2006 Tariff Filing" ("March 2 Memo") discusses allocation of import capacity for purposes of the ISO's proposed Reliability Requirements Tariff. It stated in pertinent part:

> The screen to assess the deliverability of imports identifies the megawatt amount that should be considered deliverable from outside the ISO Controlled Grid through import paths. This quantity of import capacity is then allocated to the respective LRAs for allocation between its jurisdictional entities. As stated above, this tariff is transitional as is the current construct of RA in California. Therefore, as deliverability is still being refined, some parties have raised concerns about the allocation of import capacity. *The proposed tariff language will allocate available import capacity equally to parties that enter into new import contracts.* The CAISO is also concerned about the appropriate incentives for long-term RA procurement. Thus, it is committed to continue working with stakeholders and LRAs to establish appropriate allocation methods that support and encourage long-term investment in infrastructure. [Emphasis added.]

On March 2, 2006, as part of the ISO stakeholder process, the ISO held a conference call to discuss the ISO's response to written stakeholder comments submitted on February 21, 2006. During that call, many parties expressed concern that the proposed allocation of import capacity solely on the basis of import contractual commitments injected procurement uncertainty. This uncertainty arises from the fact that, under the previously proposed language, commitments would be entered into prior to an assessment of the feasibility of the allocation.

In response to those concerns, the ISO has modified the proposed Tariff language to eliminate this uncertainty. Under the new proposal, the ISO allocates import capacity in two "buckets." The first bucket includes all contractual commitments entered into as of March 10, 2006, by non-CPUC jurisdictional Load Serving Entities for the use of intertie capacity. The second bucket includes CPUC jurisdictional Load Serving Entities in the aggregate with individual allocations being made according to CPUC adopted rules. This process, which is the same as that which the ISO has already performed for 2006, allocates intertie capacity on a forward based in a manner that encourages contracting.

## CONCLUSION AND MANAGEMENT RECOMMENDATION

Management recommends that the Board approve the policies summarized in the March 2 Memorandum and above. Management recommends the following motion.

**MOVED,**

**That the ISO Board of Governors approves the Pre-MRTU Reliability Requirements policy proposals, as outlined in the March 2 Memorandum and this addendum, dated March 9, 2006, and related attachments.**

**Further,**

**That the Board of Governors authorizes management to file the necessary tariff provisions to implement the Pre-MRTU Reliability Requirements.**

# Stakeholder Process for *Pre-MRTU Resource Adequacy Tariff Language*

## Stakeholder Process to Date

| Activity | Date | Number of Stakeholder Representatives<br>*(Telephone and onsite reps)* |
|---|---|---|
| Draft Tariff language and White Paper posted | February 3, 2006 | N/A |
| Stakeholder meeting | February 14, 2006 | 105 |
| Stakeholder written comments due | February 21, 2006 | 16 |
| Stakeholder conference call | March 2, 2006 | (This information was not available at the time this Board memorandum was prepared) |

## Stakeholder Process Going Forward

| Activity | Date |
|---|---|
| Tariff filed at FERC | March 10, 2006 |
| Expected FERC decision | May 9, 2006 |
| RA implementation | June 1, 2006 |
| | |

## Specific Written Stakeholder Comments Received and ISO Response

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
|---|---|---|---|---|
| Western Area Power Authority | Bob Chesky | Implementation | RA should be phased in over several years. Creates problems for LSE that don't have appropriate resource portfolios due to budgetary | The CAISO is accommodating the implementation schedule established by the CPUC; LSEs are in the best position to buy for their own needs. As a general principle, |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
|---|---|---|---|---|
| | | | constraints and a limited pool of 'pricier resources' | no LSE should lean on the capacity purchases of others. Therefore, the CAISO is contemplating a backstop role to allocate its costs to LSEs that are deficient. |
| | | Excluding WAPA from RA requirements | MSS that follow load are excluded from RA; WAPA also meets its own load and should also be excluded. | WAPA is an LSE within the CAISO control area. CAISO offers the ability for LSEs to meet RA in a number of ways, including signing an MSS agreement or developing an RA program under the applicable LRA. |
| | | LD Contracts | Entities that entered into LD contracts prior to 10/27/05 have preferential treatment with regard to qualifying capacity. The date should be made effective no sooner than the effective date of the Tariff. | The CAISO agrees with the CPUC that LD contracts are "fundamentally incompatible with achieving the objectives of a physical capacity-based RAR program and that, ultimately, their eligibility for fulfillment of LSE's capacity obligations should be disallowed." The 10/27/05 date for grandfathering was established by the CPUC in recognition or existing supply arrangements. Given the potential reliability problems for LD contracts no additional window to enter new contracts is warranted. |
| | | Section 40.2.1 PRM | Need to clarify when the Planning Reserve Margin ("PRM") penalty will be assessed – at submission of Demand Forecasts and Supply Plans or during a DA/RT deficiency. | The CAISO has eliminated the penalty |
| | | Section 40.2.1 PRM | Proposed penalty is too high. | The CAISO has eliminated the penalty |
| | | Section 40.2.1 PRM | Proposed penalty should not apply to WAPA as a Federal Entity. | The CAISO has eliminated the penalty |
| | | Section 40.5.1 | Q – Confirm that WAPA as an LRA would determine the qualifying | The CAISO agrees that WAPA as an LRA would make Qualifying Capacity |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
| --- | --- | --- | --- | --- |
| | | | capacity for CVP inside and outside of the Control Area. | determinations |
| | | Section 40.5.1 | Q – Confirm that WAPA as LRA would determine qualifying capacity for its LD contracts | The CAISO agrees that WAPA as an LRA would make Qualifying Capacity determinations |
| | | Section 40.5.1 | Q – Confirm that CVP units in SMUD Control Area are a "System Unit" | The CAISO cannot confirm. A "System Unit" is "one or more individual Generating Units within a Metered Subsystem controlled so as to simulate a single resource with specific performance characteristics…." Thus, CVP units in SMUD's Control Area are "System Resources," which are resources "located outside the ISO Control Area." Thus, they are subject to a limitation based on import allocation. |
| | | Section 40.5.2.1 | Q – Will the ISO determine the deliverability of WAPA resources within the ISO Control Area (e.g. New Melones)? | Yes. Western like all other LSEs in the CAISO Control Area would be subject to the CAISO's deliverability analysis |
| | | Section 40.5.2.2 | Q – Clarify the statement- "ETCs would be available to meet the requirements, but 'not necessarily to deliver market energy to load'" | Western's use of the ETCs would continue as it is today. No change is proposed with this amendment |
| | | Section 40.7 | Q – Are WAPA's CVP Hydro Units subject to MOO for RA purposes? If so, how would compensation be determined? | Nothing about this amendment proposes to change the status of WAPA's units under the FERC must-offer requirement or the compensation under the FERC must-offer requirement |
| PPM Energy | James Caldwell | Section 40.13.6 | Add verbiage related to new wind and solar capacity does not have 3 years of historic performance data. | The CAISO appreciates the comment. The criteria is based on the CPUC program and will be reviewed and, if necessary, modified |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
|---|---|---|---|---|
| | | | They should be assigned either (1) qualifying capacity of a unit in the same weather regime with similar characteristics or (2) 35% of nameplate capacity | to conform to the CPUC criteria. |
| | James Blood | Imports | Listed Assumptions for (1) Import Capacity sellers (2) Import Capacity buyers (3) POD (4) Product Elements.<br>Limitations to consider – ISO must consider multi-year assignment of import rights | The CAISO agrees that it is of importance to LSEs and suppliers to be able to rely on multi-year arrangements. Given the interim nature of this Amendment, the long-term focus on MRTU and the recent FERC rulemaking on long-term firm transmission rights, it is not possible in this filing to fully address this issue |
| | | Imports | Q – Multiyear contracts contingent on the assignment of import rights? Must consider prices and liquidity impacts | The CAISO agrees that it is of importance to LSEs and suppliers to be able to rely on multi-year arrangements. Given the interim nature of this Amendment, the long-term focus on MRTU and the recent FERC rulemaking on long-term firm transmission rights, it is not possible in this filing to fully address this issue |
| City of Vernon | Eileen Zorc | MSS | Confirm that Vernon has no must offer requirement, based on section 8.1.2 of their MSS Agreement. | The CAISO is not proposing to change the scope of the applicability of the current FERC-imposed must offer regime. Currently, MSS units are not subject to the FERC must offer requirement. Section 4.7.1 is existing tariff language |
| | | Section 40.7.1 | Add verbiage confirming that the Section does not apply to Generating Units or System Units owned or operated by Metered | The CAISO is not proposing to change the scope of the applicability of the current FERC-imposed must offer regime. Currently, MSS units are not subject to the |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
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| | | | Subsystems. | FERC must-offer requirement. Section 4.7.1 will be limited to existing tariff language, except for System Units that contract to supply Resource Adequacy Capacity with another entity |
| Cogeneration Association of CA and the Energy Producers and Users Coalition | Rod Aoki | Section 40.1 Applicability | AB 380 exempts certain types of customer generation of LSEs from RA. These criteria should be delineated in this section. | The CAISO agrees and will clarify that Public Utilities Code Section 218 arrangements will not be included |
| | | Section 40.7.1 | Needs further clarification to specify the section applies to those who sell in ISO markets, not every entity in the market. | The CAISO is not proposing to change the scope of the applicability of the current FERC-imposed must offer regime. QFs that have not been subject to the FERC must-offer program will still remain exempt. Section 4.7.1 is existing tariff language |
| Powerex | Jeff Lam | Imports | The ISO must take on the role of verifying the deliverability of imports for RA as well as verifying that importers supplying an RA capacity product on the interties have either scheduled or bid sufficient capacity into the ISO's existing markets.<br>Suggestions:<br>- Review HA schedules at interties<br>- Periodic review of sup energy bids against RA capacity obligation at the ties<br>- SCs self report and ISO verify<br>This is needed to reduce uncertainty and provide a disincentive to | The CAISO agrees with Powerex and has incorporated a schedule or offer obligation on RA imports. The CAISO is not in a position to insert proxy bids in the case an RA import does not offer consistent with their obligations. The CAISO will develop an after-the-fact review to assess if the schedule and offer obligation is complied with. |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
|---|---|---|---|---|
| | | | procure capacity at the ties. Urges another SH meeting. | |
| SMUD | Laura Lewis | Jurisdiction | Proposed tariff language infringes on policy issues that are the realm of state and local regulatory authorities. Supports CMUA comments. | The CAISO has tried to be very deferential to state and local regulatory authorities. Note that the CAISO is deferring to the forecasting standards, reserve requirements, and Qualifying Capacity determinations of *all* Local Regulatory Authorities not just the CPUC |
| | | RA obligation | Clarify that RA obligations do not apply to LSEs outside of the Control Area. | Section 40.1 states that the requirements are addressed to LSES "serving Load within the ISO Control Area |
| | | MOO | Clarify that this does not apply to entities outside of the Control Area. | The CAISO is not proposing to enlarge or diminish the scope of the current FERC-imposed must offer requirement |
| | | MOO | Method for assessing MOO costs is discriminatory and does not reflect cost causation – "Demand within California outside of the CAISO Control Area that is served by exports from the CAISO Control Area." | The CAISO is not proposing to change the current cost allocation of FERC must-offer costs for generators not supplying Resource Adequacy Capacity. The CAISO will continue to apply the outcome of the Amendment 60 proceeding |
| | | Section 40.1 Applicability | Change ("non-CPUC Load Serving Entities" to "(hereinafter collectively 'non-CPUC Load Serving Entities')". | The CAISO will consider the suggestion but is not sure of its significance |
| | | Section 40.2.1 | Add "serving load within the CAISO Control Area" after Load Serving Entity in second sentence. | The CAISO agrees that this provision applies to serving load in the CAISO Control Area |
| | | Section 40.7.1 | Need to clarify that the provision does not apply to entities outside of | The CAISO is not proposing to change the scope of the applicability of the current |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
|---|---|---|---|---|
| | | | the ISO control area to the extent that they sold power form one of its generating units into the ISO. Also remove reference to System Resources in line 4. | FERC-imposed must offer regime. Section 4.7.1 is existing tariff language. The CAISO agrees the reference to System Resources should be limited to System Resources that have contracted to supply Resource Adequacy Capacity |
| CMUA | Tony Braun | General - MOO | The ISO should limit its filing to MOO issues. | Effectively the CASIO is only addressing the MOO. However, some elements such as SC reports need to be available to the CASIO on an expected schedule and format. In addition, the CASIO believes it is appropriate to implement the settlement provisions that are necessary to reflect that some resources are RA and some are non-RA. |
| | | 2007 procurement | A RA filing this year will not affect procurement practices for LSEs this year. | The CAISO disagrees. A filing this year implements an RA program and begins the transition away from the FERC must offer obligation to the MRTU must offer program |
| | | General | Absent a Local Capacity requirement, 2007 procurement will not be affected. | The CAISO disagrees. A filing this year implements an RA program and begins the transition away from the FERC must offer obligation to the MRTU must offer program |
| | | Jurisdiction | ISO should not be involved in the planning reserve arena. This is the purview of state and local authorities. | The CAISO agrees and will remove its proposed reserve margin |
| | | PRM | Objects to imposing Planning Reserve Margin ("PRM") requirements on SCs, but not on CPUC jurisdictional LSEs. | The CAISO agrees and will remove its proposed reserve margin |
| | | PRM | Objects to penalty provisions which | The CAISO agreed to remove the proposed |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
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| | | | enforce PRM. | penalties |
| | | A.B. 380 | Section 380 - Requires that PUC in consultation with CAISO establish RA requirements for LSEs subject to CPUC jurisdiction. CMUA members are exempted from this section. Section 9620 – Defines RA for CMUA members and other local publicly owned electric utilities. This section does not mention the ISO. | The CAISO has agreed to defer to all LRAs with respect to the determination of the Planning Reserve Margin and Qualifying Capacity |
| | | Timing of filing | ISO should wait until other policy forums (State, FERC) have finished their discussions before filing. | The CAISO does not have the ability to wait given the implementation of the CPUC program in June 2006 |
| | | | CMUA provided two sets of tariff comments – *Option 1*, the preferred option limits the ISO filing to MOO only. *Option 2* – if the ISO proceeds with RA. | The CAISO appreciates the effort made by CMUA and will address the comments in the following sections |
| | | Section 40.1, 40.2, 40.3 40.4, 40.5, 40.6, 40.13 | *Option 1* – Limit filing to MOO. Strike these sections. | The CAISO disagrees. These sections are valuable in the transition towards the MRTU RA program |
| | | Section 40.7.1 | *Option 1* – Add verbiage that this sections does not apply to MSS | The CAISO is not proposing to change the scope of the applicability of the current FERC-imposed must offer regime, which does not apply to MSSs. Section 4.7.1 is existing tariff language. |
| | | Section 40.7.3, 40.7.4, 40.7.7, 40.10, 40.11.4 | *Option 1* – adjust citing | The CAISO will review the cross-references prior to the submission |
| | | Section 40.8.3, 40.8.4, 40.8.6, | *Option 1* – adjust citing, clarify the using the word "minimum" operating | The CAISO agrees that this clarification should be made. |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
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| | | | level | |
| | | Section 40.11.1, 40.12.1 | *Option 1* - Add verbiage that changes the definition of those eligible to include the outcome of FERC docket ER04-835 | The CAISO agrees that FERC must-offer cost allocation is subject to the outcome of the ER04-835 proceeding |
| | | Section 40.1 Applicability | *Option 2* – Add verbiage that this does not apply to MSS | The CAISO agrees with the comment and will add this clarification |
| | | Section 40.2 Submission of Monthly Resource Adequacy Plan | *Option 2* – The RA Plan shall be in a form mutually agreed upon by CAISO and SCs who schedule for Non-CPUC LSEs | The CAISO will work with the CPUC, other LRAs and market participants to develop an appropriate template but the tariff should not require mutual agreement |
| | | Section 40.2.1 | *Option 2* – clarify LSE "within CAISO Control Area." | The CAISO agrees that the section is addressing LSEs within the CAISO's Control Area |
| | | Section 40.2.1 Resource Adequacy Plan Compliance | *Option 2* – remove reference to Section 40 of tariff (in one area) and remove reference to penalties (in the other area). | The CAISO does not believe the reference to section 40 is incorrect. The CAISO will be removing the discussion of penalties |
| | | Section 40.3, Section 40.4 | *Option 2* – Add verbiage citing Section 9620 | The CAISO will modify the tariff to accept the Load forecast developed methodology established by the LRA, and agrees that the load forecast provided should be consistent with the requirements of Public Utilities Code section 9620 to the extent that section applies to the particular LSE. |
| | | Section 40.5.2 Net Qualifying Capacity | *Option 2* – clarify the portion of the tariff re: Net Qualifying Capacity. | The CAISO will consider adding a cross-reference as requested by CMUA but doesn't believe it is necessary for clarification |
| | | Section 40.5.2.1 | *Option 2* – deliverability analysis is subject to FERC review. | The CAISO does not agree that language stating the analysis is subject to FERC |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
|---|---|---|---|---|
| | | | Add reference to the fact that once a generating unit is deemed deliverable it will always deemed deliverable for Net Qualifying Capacity purposes. | review is warranted. If an entity believes that the CAISO has improperly conducted the study (or performed any other task under the tariff) the remedy is to file a complaint.<br><br>However, the CAISO can agree with the principle that a resource will always be deliverable. In fact, this is embodied in the recently approved Large Generator Interconnection Procedures. However, there may be cases where this is not practical and must be addressed on a case by case basis. For example, the loss of a large load at or near a generator could cause a resource's deliverability to be reduced. |
| | | Section 40.5.2.1 | *Option 2* – Q – Is deliverability likely to be degraded by other events? | Not likely but possibly – see the response to the prior entry |
| | | Section 40.5.2.2 | *Option 2* – Added reference to FTR and converted rights and pre-existing rights to deliver to the ISO.<br>Change verbiage to reflect that CPUC and Non-CPUC LSE be treated similarly.<br>LSEs entering into long-term commitments for capacity shall receive priority.<br>Remove references to requirements of sharing information at the end of the section. | The CAISO does not believe all these changes are appropriate as the allocation is based on the existing supply arrangements. The CAISO agrees that the allocation of import capacity for resource adequacy purposes should be on a comparable, non-discriminatory basis. The CAISO agrees that it is of importance to LSEs and suppliers to be able to rely on import capacity which must be allocated in a non-discriminatory manner, including multi-year arrangements. However, contracts information must be made available to the CAISO for meet these objectives. Given the interim nature of this |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
|---|---|---|---|---|
| | | | | Amendment, the long-term focus on MRTU and the recent FERC rulemaking on long-term firm transmission rights, it is not possible in this filing to further address this issue. |
| | | Section 40.6 | *Option 2* – Submission of Supply plans – CMUA notes that this does not obligate LSEs to use the same supply identified in the Supply Plan for any purpose. | The LSE is obligated to use the resources in the Resource Adequacy Plan not the supply plan – however, the CAISO would expect that there would be consistency between the plans |
| | | Section 40.7 | *Option 2* - Remove reference to System Resources. Add verbiage that this does not apply to MSS. | The CAISO agrees to delete the reference to Dynamically Scheduled System Resources<br><br>The CAISO is not proposing to change the scope of the applicability of the current FERC-imposed must offer regime. Section 4.7.1 is existing tariff language. |
| | | Section 40.7.3, 40.7.4, 40.7.7 | *Option 2* – Adjust citing | The CAISO will review the cites prior to final submission |
| | | Section 40.7.5 | *Option 2* – Q – asks for clarification whether the "emergency only" is a substitute for the Modified Must Offer. | The CAISO is not intending to modify the applicability of the FERC MOO and is relying upon the current form of MSS agreements.. Thus, the "emergency only" provision is not necessary in this tariff amendment and has been removed. |
| | | Section 40.8.3, 40.8.4, 40.8.6, 40.10, 40.11.4 | *Option 2* – adjust citing, clarify the using the word "minimum" operating level | The CAISO agrees with this clarification. |
| | | Section 40.11.1, 40.12.1 | *Option 2* - Add verbiage that changes the definition of those eligible to include the outcome of | The CAISO agrees that this filing is not meant to prejudice the litigation in ER04-835 and that if that proceeding requires |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
|---|---|---|---|---|
| | | | FERC docket ER04-835 | modification of this provision, it will be modified in compliance with that order |
| | | Section 40.13.1 | *Option 2* – Remove (ii) verbiage | The CAISO agrees with this suggestion and has modified the draft accordingly. |
| | | Section 40.13.5 | *Option 2*- Remove this section. | While the CAISO would like to get rid of LD contracts, this provision tracks the CPUC's program and the CAISO has included it for comparability |
| AReM | Sue Mara | Section 40.2, 40.2.1, 40.3, 40.4, 40.5, 40.5.1, 40.5.2, and throughout. | Change verbiage to be consistent with language of CPUC rules: Replace "plans" with "showings" and "submittals"; Change "Net Qualifying Capacity" to "Qualifying Capacity adjustments" | The CAISO is considering these comments as well as similar but not identical comments from others regarding these provisions |
| | | Section 40.2 Submission of Monthly Resource Adequacy Plan | Delete the first sentence. Clarify that document should be submitted to the CPUC and they will provide the info to the CAISO. | The CAISO disagrees that the plan must be submitted first to the CPUC and then from the CPUC to the CAISO. The Scheduling Coordinator can submit it directly to the CAISO |
| | | Section 40.5.1 | Add reference to Section 40.13 within the body. Delete last sentence. | The CAISO agrees to add the cross-reference |
| | | Section 40.5.2 Net Qualifying Capacity | AreM notes that timing is extremely important as it relates to adjustments to Qualifying Capacity. | The CAISO agrees that it needs to work with the CPUC and other LRAs to provide the information in a timely manner. |
| | | Section 40.5.2.1 | Add - ISO will review deliverability analysis inputs and draft results with Market Participants and post adjustments to our website within 90 days. | The CAISO has stated its intention to post the results of its deliverability analysis in Section 40.5.1. The CAISO agrees to include language indicating that the CAISO will notify suppliers of changes in net qualifying capacity prior to publication to |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
|---|---|---|---|---|
| | | | | allow for resolution of disputes. |
| | | Section 40.5.2.2 | Deliverability of Imports – suggests changes to indicate that CPUC and Non-CPUC LSEs are treated the same. | The CAISO agrees that the allocation of import capacity for resource adequacy purposes should be on a comparable, non-discriminatory basis. The intent of the section is to conform to those principles. |
| | | Section 40.6 | Supply plans must be held in confidentiality. | The CAISO agrees that the supply plans could be held in accordance with the confidentiality provisions of the tariff |
| | | Section 40.7.5 | The ISO is ignoring the MCC buckets methodology. | CAISO disagrees. The CAISO recognizes the CPUC has included the MCC concept. Therefore, the CAISO expects to fully support the MCC approach. |
| | | Section 40.7.7 | Need to clarify citing of sections within this portion. | The CAISO agrees the cites need to be updated |
| | | Section 40.8.7 | Change verbiage in title from "Capacity" to "Generation" | The CAISO is not proposing to make changes to the FERC must-offer program at this time in this filing. Further, the proposed change is non-substantive (as titles do not have substantive meaning under the tariff) |
| | | Section 40.13.1 | Delete (ii) | The CAISO agrees with this suggestion and has modified the draft accordingly. |
| NCPA | Tony Zimmer | Metered Subsystem ("MSS") | Requests confirmation that MSS and MSS Agreement are exempt from the CAISO Section 40, including pre-MRTU Resource Adequacy Requirements, MOO and CAISO Default Qualifying Criteria. | The changes to section 40 are not meant to either enlarge or diminish the requirements on MSS Operators, which are currently exempt from the FERC must offer obligation |
| TURN | Mike Florio | Deliverability of Imports | A reasonable and non-discriminatory method must be developed to ensure that CPUC and | The CAISO agrees that it is of importance to LSEs and suppliers to be able to rely on import capacity which must be allocated in a |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
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| | | | Non-CPUC LSEs receive a fair share of import capacity.<br>- Adopt an a priori allocation methodology based on load ratio share. Allow a second chance request once allocation has been made so that LSEs will have opportunity to fine tune capacity allocations.<br>- Must make sure this is done early enough in the prior year so that resource commitments can be made. | non-discriminatory manner, including multi-year arrangements. Given the interim nature of this Amendment, the long-term focus on MRTU and the recent FERC rulemaking on long-term firm transmission rights, it is not possible in this filing to fully address this issue |
| PG&E | Arthur Haubenstock | Section 40.2, 40.4, 40.5.2.2, 40.6, 40.7.1, 40.7.3, 40.7.5, 40.7.6, 40.10.1 | Clarifying edits. | The CAISO is considering these comments as well as similar but not identical comments from others regarding these provisions |
| | | Section 40.2.1 | Replace "fail" with "the CAISO does not believe"<br>Add word "potential" before deficiency | The CAISO agrees to replace "fail" with something else such as the CAISO "identifies as not demonstrating compliance"<br>The CAISO agrees to add the word "potential" |
| | | Section 40.5.2.1 | Add a 5-year forecast.<br>Add details regarding deliverability analysis.<br>Remove last sentence. | While the CAISO agrees with the long-term value of a 5-year forecast, it is not appropriate at this time to be prescriptive on this point. Therefore, the CAISO remains committed to work with the stakeholders to develop such a modification to the deliverability studies. |
| SCE | David Schiada | Section 40.2 | Define "Resource Adequacy Plan" – | The CAISO agrees that the Resource |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
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| | | Submission of Monthly Resource Adequacy Plan | the month-ahead compliance showing templates outlined in CPUC RAR. Add verbiage to include that it is in the form "and manner" approved by CPUC. | Adequacy Plan should be a defined term and will add a definition to Appendix A. However, SCE's suggested language is too narrow in that the term also will be used for LSEs other than CPUC jurisdictional LSEs. |
| | | Section 40.5.2 Net Qualifying Capacity | Net Qualifying Capacity determinations will comport with RA timelines established by LRAs. | The CAISO agrees that it needs to work with the CPUC and other LRAs to provide the information in a timely manner. |
| | | Section 40.5.2.2 | Results of Deliverability Analysis shall be posted on the ISO website within RA timelines established by LRAs. | The CAISO agrees that it needs to work with the CPUC and other LRAs to provide the information in a timely manner. |
| | | Section 40.6 | Define "Supply Plan" – not the same as "use limited resource plan" | The CAISO agrees and will add a definition to Appendix A |
| | | Section 40.7 | Revise tariff language to reflect that<br>- Non-dispatchable QFs or use limited resources that are also RA resources are not subject to the same must offer obligations as Dispatchable resources.<br>- The ISO will not submit proxy sup energy bids for QF or use limited resources for the un-bid quantity of those resources. | The CAISO is not proposing to change the scope of the applicability of the current FERC-imposed must offer regime. QFs that have not be subject to the FERC must-offer program will still remain exempt. Section 4.7.1 is existing tariff language |
| | | Section 40.7.7 | Clarify which entities are subject to sanctions | The CAISO does not believe the requested clarification is necessary, the SC submitting the supplemental energy bid or responsible for the proxy bid would be the responsible entity |
| Sempra Global (non-utility business) | Thomas Corr | Section 40.7.1 | There was an expectation that FERC MOO would go away. There | In the 2/9/2006 MRTU filing, the CAISO has proposed termination of the FERC must- |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
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| | | | is no justification for expanding the reach of this program by including Dynamically Scheduled System Resources. | offer program. It is being retained for this interim period.<br><br>The CAISO agrees that the scope of section 40.7.1 should stay the same as today except for an obligation on System Resources that contract to provide Resource Adequacy Capacity |
| Williams Power Company, Inc. | Tim Muller | MOO | Must-Offer obligation should be narrowly applied to RA Qualifying Capacity only. | The CAISO is not proposing to change the scope of the applicability of the current FERC-imposed must offer regime. Section 4.7.1 is existing tariff language. The narrowing requested by Williams is part of the CAISO's MRTU proposal filed on 2/9/2006 |
| | | Section 40.1 Applicability | Participating Generators serving station load should be expressly exempt from requirements of Section 40 and from being an LSE. Noted in Tariff section 40.1 | The CAISO agrees |
| | | Section 40.8.3 MOO - Imbalance Energy Payment | Strongly opposes the complete elimination of the imbalance energy payment for units that may be providing Qualifying Capacity. At most these payments should be prorated based on the ratio of the Generating Units Qualifying capacity to the Pmax. | Under the existing Must-Offer rules approved by the FERC, a resource that is denied a Must-Offer Waiver is compensated for its minimum load costs in addition to receiving the an imbalance payment for minimum load. While this has been identified as a "double payment," FERC has justified it as appropriate for a capacity payment *until a resources are able to earn a capacity payment through another mechanism such as a Resource Adequacy* |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
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| | | | | *contract.* Now that resources that have the opportunity to enter into an RA contract, it is appropriate to modify the minimum load cost compensation methodology for such contracted resources to ensure that such resources are not paid less their minimum load cost after considering the compensation from the imbalance energy market. The existing minimum load cost compensation method will be maintained for resources that are not under an RA contract. |
| | | Section 40.6 Supply Plan | Q – Why is this needed in addition to the LSE RA showing? If it is for cross validation then this process must be expressly outlined in the tariff. Tariff section must outline how it will treat or reconcile any differences. | Williams is correct. The submission of the supply plan is for purposes of validation. The CAISO does not believe that further clarification is necessary. Section 40.2.1 describes how the CAISO will proceed if there are problems with the Resource Adequacy Plans submitted by SCs for LSEs. |
| | | Qualifying Capacity Details | The ISO must include sufficient detail for all provisions that affect rates and terms to allow the Commission to determine if they are just and reasonable. | The CAISO has stated its intention to post the results of its deliverability analysis in Section 40.5.1. The CAISO agrees to include language indicating that the CAISO will notify suppliers of changes in net qualifying capacity prior to publication to allow for resolution of disputes. Further, the CAISO anticipates that the essential information necessary from a testing and verification process may already be available under existing tariff provisions. |
| | | Proxy Prices | The ISO should use the true daily gas price index. (Section 40.10.1) | The CAISO is not proposing to make changes to the FERC must-offer program at |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
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| | | | | this time in this filing. |
| | | MOWD | The process and criteria for Must Offer Waiver Denials ("MOWD") must be part of the Tariff, not the Operating Procedures. | The criteria are fundamentally the existing tariff language from section 5.11.6.2 (section 40.1.6.2 in the Simplified and Revised Tariff). |
| | | Definitions | The ISO should create precisely defined terms for all new terms introduced in Section 40. | The CAISO agrees that the new defined terms (similar to those developed in Appendix A of the Tariff for the MRTU filing) should be added to this filing |
| | | Section 40.1 Applicability | Clarifying terms added. | The CAISO is considering these comments as well as similar but not identical comments from others regarding this provision |
| | | Section 40.2 Submission of Monthly RA Plan | Edit - "web site" or "website." | The typographical correction has been noted |
| | | Section 40.2.1 RA Plan Compliance | Include formula rate for determining "X". | The CAISO proposes to eliminate the penalty |
| | | Section 40.3 Demand Forecasts | Narrow the kind of data and information that is being requested. | The CAISO disagrees that the data provision requirements are overbroad. |
| | | Section 40.4 PRM | Q – Will the ISO object if the LRA establishes a Planning Reserve Margin "PRM") of less than 15%? If not, then item (b) should apply only when the LRA has not established a PRM. | The CAISO has agreed to remove the 15% requirement |
| | | Section 40.5.2 Net Qualifying Capacity | The testing and verification process and the deliverability analysis must be set forth in the tariff. | The CAISO disagrees. The concepts should be reflected in the tariff but the implementing detail can be reflected in manuals or procedures |
| | | Section 40.5.2.1 Deliverability within | Clarifying edits. Deliverability and availability of different concepts that | The CAISO agrees with the suggested edit "available" will be revised to "able" |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
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| | | ISO Control Area | should not be mixed. | |
| | | Section 40.5.2.2 Deliverability of Imports | Clarifying edits.<br>Q – When this ISO informs the SC for a Non CPUC LSE that its RA plan exceeds the non CPUC LSE allocation, the tariff states that it will reduce all import RA Capacity on a pro rata basis or reduce a specific import as instructed by the SC. Confirm that the ISO will only reduce all import RA Capacity for that non-CPUC LSE (on a pro rata basis) | The CAISO agrees and will make a clarifying modification. |
| | | Section 40.7.1 Applicability | Will there be a defined term for "capacity"? | This section is existing tariff language based on the existing FERC must-offer program |
| | | Section 40.7.2 Available Gen | Clarifying edits | This language is existing language that is not modified by the proposed Amendment |
| | | Section 40.7.3 Reporting Requirements for Non Participating Gen | Need to provide more detail on what must be filed. | This language is existing language that is not modified by the proposed Amendment it comes from Section 5.3.11 (or Section 40.1.3 of the Simplified and Revised Tariff) |
| | | Section 40.7.4 Obligation to offer Available Capacity | Change "Capacity" to "Generation" | The CAISO does not agree that this change is necessary. The term Generation is used in the existing Tariff and given the whole unit nature of the offer obligation under the Pre-MRTU Tariff continues to be valid. |
| | | Section 40.7.5 Submission of Bids and Applicability of the Proxy Price | How will ISO enforce proxy bids for MO Generators for which it does not have real-time SCADA?<br>ISO must include criteria by which it will determine waiver denials. | The same way it does today under the existing must-offer program |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
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| | | Section 40.7.6 MOO Process | Clarified verbiage adding specificity to granting waivers.<br>Added wording about Generating Unit start-up time. | The CAISO is considering these comments as well as similar but not identical comments from others regarding these provisions |
| | | Section 40.7.7 Penalties for Non-Compliance | Need exceptions for forced outages and approved outage schedules. | The CAISO agrees that outages |
| | | Section 40.8.1, 40.8.6, 40.8.7, 40.11.6, 40.12.7, 40.13.4 | Added clarifying language. | The CAISO is considering these comments as well as similar but not identical comments from others regarding these provisions |
| | | Section 40.9 Criteria of Issuing Must-Offer Waivers | Item 1 is contrary to 10/31/05 Amendment 60 initial decision. Current wording does not appear to authorize ISO to grant waivers to commit units for Local reliability requirements. | As the CAISO has explained in its brief on exceptions to the initial decision, the CAISO does have the express authority in its Tariff to deny must-offer waivers if there will otherwise be insufficient "on-line generating capacity to meet operating reserve requirements." Section 40.9 is fundamentally the current CAISO Tariff Section 5.11.6.2 |
| | | Section 40.10.1 | ISO should use RMR equation C1-8 as the basis for proxy prices. | It is pre-mature in the context of RA to use the daily gas. This issue may be dealt with in context of other proceedings. |
| | | Section 40.13 CAISO Default Qualifying Capacity Criteria | Need more detail regarding the method for deriving Qualifying Capacity from 6 hours of peak data over a 3-year period.<br>Q – How often will the Qualifying Capacity Assessment be made? | The CAISO has based this tariff language on the CPUC order. The CAISO anticipates working with the CPUC to add additional detail that does not need to be reflected in the tariff language. The Qualifying Capacity determination should be adjusted only when circumstances relating to the resource |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
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| | | | | change |
| | | Section 40.13.7 Geothermal | Q – How will the de-rate be determined? | The CAISO has based this tariff language on the CPUC order. The CAISO anticipates working with the CPUC to add additional detail that does not need to be reflected in the tariff language. |
| | | Section 40.13.12.2 Non-Dynamically Scheduled System Resources | Deleted verbiage related to Operating Reserves. It is not "germane to whether the System Resources should count." | The CAISO agrees. |
| SDG&E | Tiff Nelson | Implementation | There must be close coordination between CPUC, CAISO and CEC with regard to RA compliance monitoring, so that CPUC and Non-CPUC LSEs are handled appropriately. | The CAISO supports the comment and agreed that close coordination is essential in all aspects of the Resource Adequacy program |
| | | Section 40.2.1 | The proposed penalty in the CAISO tariff differs from the penalty in CPUC RA. Suggest that a capacity market is a better approach to the issue. | The CAISO has agreed to remove the proposed penalty |
| | | MOO | SDG&E accepts that MOO is applied differently between RA MOO and FERC MOO, for the limited period until MRTU or a centralized capacity market are in place. | The CAISO appreciates SDG&E's recognition of the proposal as an interim measure pending implementation of MRTU |
| | | Supply Plans | SDG&E supports the concept of an RA obligation of the Scheduling Coordinators of generators reporting the RA Status of their | The CAISO agrees that this limited reporting obligation on generators will serve as a useful verification tool |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
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| | | | capacity to the CAISO. | |
| | | Section 40.6 Submission of Supply Plans | Include verbiage that incorporates the concept that generation could have commitments to multiple LSEs through joint ownership or LSE contracting for partial capacity (change "an LSE" to "any LSE") | The CAISO agrees with the comment and proposes to modify the language in Section 40.6 to be revised from "to an Load Serving Entity" to read "to a Load Serving Entity or group of Load Serving Entities" |
| | | Section 40.7.1, et al. | Clarify that Dynamically Scheduled System Resources do not include Qualifying Facilities that are also dynamically scheduled. | The CAISO agrees that the scope of 40.7.1, the current FERC must-offer requirement should not have been diminished or expanded except for System Resources that commit to supply Resource Adequacy Capacity |
| California Department of Water Resources, State Water Project | Holly Cronin | Eligibility | AB380 expressly exempts the State Water Project from RA requirements. As an LRA CDWR-SWP will adopt its own RA program. | The CAISO agrees that as an LRA the SWP will establish the parameters of its own program. SWP is excluded from the definition of LSE, but will be required to develop, in cooperation with the CAISO, a program that ensures it will not unduly rely on the resource procurement practices of other Load Serving Entities. |
| | | Reliability Costs | The relationship between the RA requirement and continued CAISO Reliability cost incurrence has not been addressed.<br>Q - Does the ISO expect reliability purchases to decrease due to RA? What are the projections?<br>Q – How does the ISO measure the relative effectiveness of both RA and CAISO reliability programs? It this going to be public information? | The CAISO disagrees. Costs for Resource Adequacy Capacity is born by the respective LSE; cost responsibility for additional resources called under the FERC-Must Offer obligation will continue to be assessed based on the outcome of Amendment No. 60. The CAISO has not made any projections of decreases in costs under the FERC MOO. |

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| | | | Q – What public reporting with the ISO be providing to give LSEs feedback on the efficacy of their RA acquisitions in reducing ISO reliability costs? | |
| | | RCST | Q - What future negotiations are planned? How will intervenors be able to participate? | This issue is beyond the scope of this filing. |
| | | Applicability | Entities exempted from RA under state law should not be subject to RA requirements of the ISO tariff | SWP is excluded from the definition of LSE, but will be required to develop, in cooperation with the CAISO, a program that ensures it will not unduly rely on the resource procurement practices of other Load Serving Entities. |
| | | Section 40.11.1, 40.12.1 | ETCs and Interruptible, Participating Load should not be required to meet RA requirements and should not be charged reliability-related costs, including emissions and start up. | As the CAISO is not proposing to eliminate the use of the FERC MOO, the cost allocation is also appropriate. |
| | | Section 40.8.6, Minimum Load Cost Allocation | Continued use of Amendment 60 allocation is not acceptable and CDWR-SWP will oppose this at FERC.<br>- AB 380demonstrates that CDWR-SWP is exempt from reliability charges<br>- Amendment 60 was not intended to be extended<br>- Amendment 60 precludes demand response, which is a critical component of successful | As the CAISO is not proposing to eliminate the use of the FERC MOO, the cost allocation is also appropriate. |

| Entity | Commenter | Topic/Issue | Stakeholder Comment | ISO Response |
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| | | | electric markets.<br>- CAISO should bill must offer costs based on a coincident peak load ratio share basis<br>Reliability costs should be allocated to loads using ETCs | |
| | | Section 40.11.1, 40.12.1, 40.12.7 Emissions and Start Up | Need tariff clarification that these costs are paid only to must offer generators that are actually operating under must offer waiver denials. | As this is existing tariff language, the CAISO does not believe the clarification is warranted |
| | | Section 40.13.9 | ISO should use defined terms in this area – Curtailable Demand in lieu of Dispatchable Demand. | The CAISO agrees that the term "Dispatchable Demand Resource is incorrect. |
| | | Section 40.1 Applicability | Clarification that the State Water Project is excluded from the definition of a Load Serving Entity. Additionally adds verbiage related excluding customer generation for standby service or is not physically interconnected to the grid. (AB 380) | SWP is excluded from the definition of LSE, but will be required to develop, in cooperation with the CAISO, a program that ensures it will not unduly rely on the resource procurement practices of other Load Serving Entities |
| | | Section 40.2.1 | Provide the calculations underlying the penalty $/MW and the mechanism for deriving this amount | The CAISO has removed the proposed penalty |
| | | Section 40.3, 40.4 | Clarify that the Demand Forecast and PRM are net of demand served by ETCs or is interruptible, non-firm or participating load. | SWP is excluded from the definition of LSE, but will be required to develop, in cooperation with the CAISO, a program that ensures it will not unduly rely on the resource procurement practices of other Load Serving Entities. |
| | | | | |

CALIFORNIA ISO

California Independent
System Operator

# Pre-MRTU Reliability Requirements 2006 Tariff Provisions

ISO Board of Governors Meeting
March 8-9, 2006

Phil Pettingill

Manager, Infrastructure Policy and Contracts

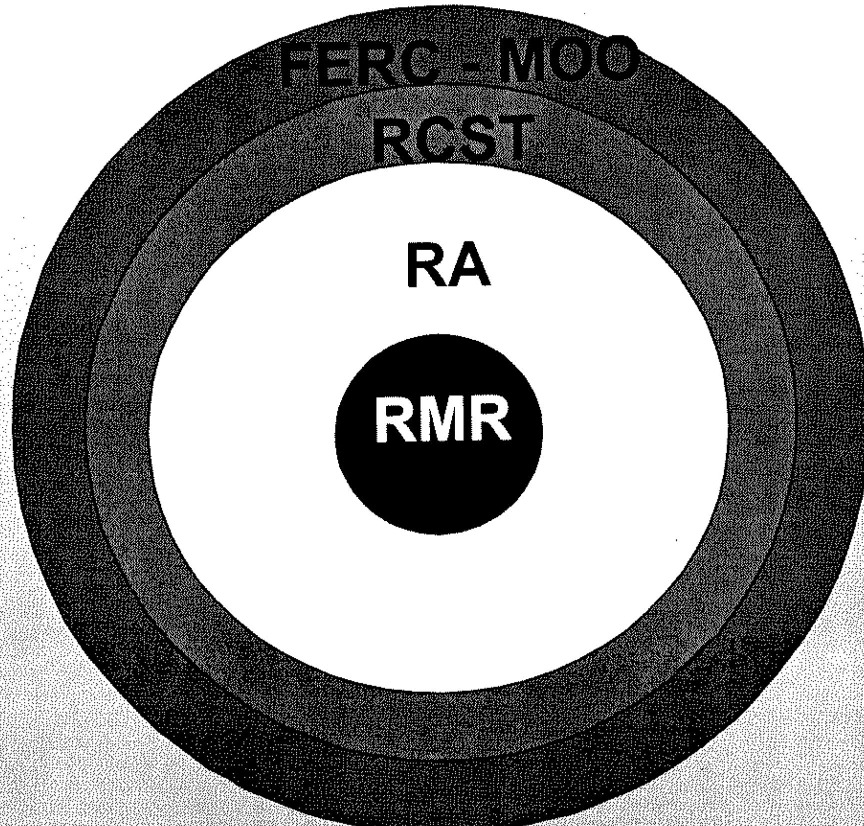
# Background

- CPUC RA Rulemaking for 2006 complete
- CPUC RA Rulemaking for 2007 proceeding is just beginning
- MRTU Tariff addresses RA integrated with MRTU Market Design
- Need tariff to that addresses RA integrated with existing Market Design

# Guiding Principles for 2006 Tariff

- Rely upon existing Tariff provisions where possible
  - Current MOWD process and MLCC cost allocation
- Minimize changes to existing systems
  - Settlement of unit commitment costs are modified for RA resources vs. resources subject to FERC MOO
  - No expansion or reduction of resource types currently called under FERC MOO
- Deference to CPUC and Local Regulatory Authorities
  - CPUC has obligated System resources to offer to CAISO
- Until RCST resolved, 2006 Tariff relies upon FERC MOO

# Sources of Reliability Capacity Available to CAISO



# Structure of Tariff

- Utilizes “must offer” Section 40 of the Simplified and Reorganized (“S&R”) Tariff
  - FERC approved February 24, 2006
- RR provisions for SCs of LSEs
  - Deference to LRAs – counting and forecasting
  - Default criteria when LRAs do not adopt
  - CPUC and Non-CPUC LSEs treated comparably
    - Monthly Reports of their RA resources
- RR provisions for SCs of resources
  - Supplier obligations
  - Monthly Supply Plan, Deliverability
  - FERC MOO

# Summary of Changes

- Resources
  - RA preference in Commitment decisions
  - RA settled differently than FERC MOO
- Comparable consequences for failure to meet provisions of these reliability requirements
- Deliverability
  - Generation to aggregate of load
  - Imports to the CAISO controlled grid
- No Local Capacity Requirements
  - Rely upon current mechanisms; RMR, FERC-MOO, Section 42

# Modified Settlements

- Example: Two similar resources
  - Minimum Load = 50 MW
  - Minimum Load Energy Costs = $70/Mwh
  - Imbalance Energy Price = $50/Mwh

- Unit 1 – (Existing MLCC Method)
  - Minimum Load Cost Compensation = 50 MW x $70/Mwh = $3500/hr
  - Imbalance Energy Payment = 50 MW x $50/Mwh = $2500/hr
  - Total Compensation = $6000 per hour

- Unit 2 – (Proposed MLCC for RA Resources)
  - Imbalance Energy Payment = 50 MW x $50/Mwh = $2500/hr
  - Uplift Payment = 50 M x ($70-$50) = 50 Mw x $20/Mwh = $1000/hr
  - Total Compensation = $3500 per hour