California Independent
System Operator Corporation

November 26, 2013

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: California Independent System Operator Corporation
Docket No. ER14- ___-000

Tariff Amendment to Implement Real-Time Market Design Enhancements Related to Order No. 764

Dear Secretary Bose:

The California Independent System Operator Corporation ("ISO") submits revisions to the ISO tariff to enhance its real-time market design.[1] These market enhancements will allow the ISO to more effectively and efficiently integrate a large amount of variable energy resources into the resource fleet serving ISO customers, to align its market design with certain reforms mandated in the Commission's Order No. 764,[2] and to address identified inefficiencies in the ISO's real-time market that will also facilitate reinstatement of convergence bidding on the interties.

The ISO respectfully requests that the Commission issue an order by February 13, 2014 that accepts the proposed tariff revisions effective April 1, 2014. An order by February 13, 2014 accepting the ISO's proposal is needed to facilitate the proposed schedule for the ISO's new energy imbalance market with other balancing authority areas in the West.

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[1] The ISO submits this filing pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d. The ISO is sometimes referred to as the CAISO. Capitalized terms not otherwise defined herein have the meanings set forth in the ISO tariff, and references to specific sections and appendices are references to sections and appendices in the ISO tariff unless otherwise indicated.

[2] *Integration of Variable Energy Resources*, Order No. 764, FERC Stats. & Regs. ¶ 31,331 ("Order No. 764"), *order on reh'g and clarification*, Order No. 764-A, 141 ¶ 61,232 ("Order No. 764-A") (2012), *order on clarification and reh'g*, Order No. 764-B, 144 FERC ¶ 61,222 (2013).

I. Executive Summary

The ISO's proposal to change intertie scheduling and settlement from an hourly to a 15-minute basis (while retaining hourly scheduling options on the interties to prevent seams issues in the region), and to establish a 15-minute settlement for internal resources and convergence bids, will have numerous benefits. These market design enhancements will facilitate the scheduling of variable energy resources over the interties and the integration of such resources into the ISO markets, while allowing all resources to be scheduled more effectively through more granular schedules with shortened forecast lead times. These enhancements will modify the ISO markets to allow for 15-minute energy scheduling to enable resources to better manage their exposure to imbalance energy charges, while providing options for hourly intertie transactions in order to avoid seams issues with other parts of the West. Lastly, these enhancements align the settlement of internal and intertie transactions at the same time and at the same prices and corrects the problems that led to suspension of convergence bidding on the interties, allowing for the phased reintroduction of convergence bidding on the interties.

A major focus of the ISO's market and product review efforts in recent years has been to develop market design improvements that will facilitate the integration of renewable resources and support the region's ambitious renewable portfolio standards and environmental goals. The ISO supports the Commission's initiatives to eliminate barriers to the integration of renewable resources, and the ISO has already undertaken numerous efforts to enhance its markets to enable participation of renewable resources to participate in the ISO markets more economically. This is another important step in that direction.

Many renewable resources, including wind, solar thermal and photovoltaic, and hydrokinetic generating facilities, have variable energy output within the operating hour. The Commission's Order No. 764 removes barriers to the integration of variable energy resources by requiring each public utility transmission provider to: (1) offer an option for intra-hourly transmission scheduling; and (2) require variable energy resources to report meteorological and forced outage data for the purpose of power production forecasting. Order No. 764 requires only an intra-hour scheduling option and does not mandate that the ISO settle all intertie transactions, much less all resources, on a 15-minute basis. The Commission has, however, invited transmission providers to submit alternative proposals that are consistent with or superior to the intra-hour scheduling requirements of Order No. 764 and that are otherwise just and reasonable and not unduly discriminatory or preferential.[3] The real-time market design enhancements described in this filing are such a proposal.

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[3] Order No. 764 at P 107. *See also Midcontinent Ind. Sys. Operator, Inc.,* 145 FERC ¶ 61,064 at P 23 (2013) (" . . . in Order No. 764, the Commission addressed concerns about the alignment between the scheduling interval and the settlement interval by stating that, to the extent

In response to the Commission's directives in Order No. 764, the ISO initiated a stakeholder process that, among other things, sought to: (1) orient the ISO's real-time market design to support improved participation of variable energy resources; (2) provide the option for 15-minute scheduling on the interties; (3) continue to support fixed hourly intertie transactions and minimize seams issues in the Western Interconnection; and (4) address identified market inefficiencies with the ISO's current real-time market design (including inefficiencies that led to the suspension of convergence bidding on the interties).

The ISO's proposal to schedule and settle both intertie and internal resources at the same financially binding 15-minute intervals will allow internal and intertie resources to compete and be priced on an equal basis with one another in the real-time market using the existing market functionality. The ISO respectfully submits that these enhancements offer numerous benefits beyond compliance with the minimum requirements of Order No. 764, including:

- A market that takes into account the characteristics of variable energy resources. Not only do these changes accommodate scheduling of variable energy resources over the interties, but they also allow all resources to be scheduled more effectively through more granular schedules with shortened forecast lead times.

- Elimination of the settlement uplift charges currently attributable to settling intertie resources at hourly prices while settling internal resources at five-minute prices. The proposed changes will result in both intertie and internal resources being scheduled and settled in the same market run. This will eliminate inefficiencies that currently occur, for example, when imports are reduced in the current hour-ahead scheduling process and then the energy is replaced using internal resources in the five-minute dispatch at higher prices.

- A real-time market structure that allows for 15-minute energy scheduling in accordance with Order No. 764, while also including provisions for scheduling intertie transactions in hourly blocks (settled at 15-minute prices) to avoid seams issues in the West. The more accurate scheduling of variable energy resources as a result of these improvements will result

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a public utility transmission provider believes that aligning the imbalance settlement with the intra-hour scheduling interval or implementing sub-hourly dispatch will result in more efficient operation, provide appropriate price signals to customers, or other potential issues, it may seek authorization to do so under section 205 of the FPA. The Commission offered that such proposals could be submitted contemporaneously with the compliance filing in response to the Final Rule."). The ISO's filing is consistent with the guidance in both Order No. 764 and the order quoted above.

in more efficient real-time commitment and dispatch decisions of both internal resources as well as import and export schedules.

- Correction of the issues arising from settling intertie convergence bids at hourly prices while settling internal convergence bids at five-minute prices that led to suspension of convergence bidding on the interties. Under the ISO's proposal, convergence bidding on the interties will be phased in starting 12 months after the market enhancements have been implemented to allow for a "shakeout" period after these significant market changes are in place. In particular, this approach will permit approximately six months of experience with the proposed new energy imbalance market before convergence bidding on the interties starts to be reintroduced. When convergence bidding on the interties is reintroduced, all convergence bids will be settled – along with physical intertie and internal resources – at fifteen-minute market prices.

The ISO's filing provides significant improvements to the ISO's existing participating intermittent resource program. That program was designed to address exposure to real-time imbalance energy charges caused by involuntary deviations from instructions due to inability to control ones fuel source and output. The implementation of 15-minute scheduling and settlements establishes a market structure that affords more appropriate treatment of variable energy resources than the existing participating intermittent resource tariff provisions. The ability of these resources to use a forecast closer to real-time, and the ability to establish more granular schedules in the fifteen-minute market than their current hourly base schedules, will mitigate the exposure of these resources to price variability in the five-minute real-time dispatch. In addition to providing intermittent resources with a scheduling opportunity close to real-time that minimizes imbalance exposure, the ISO's proposed market enhancements provide participating intermittent resources with the ability to submit economic bids indicating their willingness to be curtailed in over-generation conditions. These resources will be able to maximize their participation in the market by responding to price signals. This provides significant benefits to both variable energy resources and the ISO's ability to maintain system reliability.

The real-time market enhancements proposed in this filing will satisfy the intra-hour scheduling objectives of Order No. 764, while addressing inefficiencies in the current real-time market design, and aligning that market design with the needs of variable energy resources that will constitute an increasing percentage of the resource fleet serving ISO customers in accordance with California law and policy initiatives.

Stakeholders have generally supported the key features of the real-time market design enhancements, recognizing that the proposed design will help integrate variable energy resources, resolve existing issues with the pricing of

intertie transactions, and address price volatility that currently exists in the real-time market.

A number of stakeholders and the ISO Department of Market Monitoring expressed concern about reinstating convergence bidding concurrently with the proposed design changes. The real-time market design enhancements constitute significant changes to the market, especially to the scheduling and pricing of intertie transactions. In addition, the ISO is planning in Fall 2014 to implement the energy imbalance market, which will expand the real-time market to include other balancing authorities. Based on stakeholder feedback expressing reservations about adding intertie convergence bidding at the same time these other significant market design changes are implemented, the ISO proposes an initial twelve-month period without intertie convergence bidding to allow the ISO and market participants to observe the operation of the new fifteen-minute market under various seasonal conditions. The ISO then proposes to phase in the reinstatement of convergence bidding on the interties through the use of gradually increasing position limits, which will limit the megawatt quantity of convergence bids that may be submitted by a scheduling coordinator to a specified percentage of the intertie transfer capability. The proposed percentages and time periods for these position limits are the same as the position limits approved by the Commission when convergence bidding first was implemented on the interties.

Some stakeholders have argued that the ISO should maintain existing tariff provisions for resources participating in the participating intermittent resource program to net real-time energy imbalances over the month. In response, the ISO has proposed a transitional protective measure for participating intermittent resources that have a limited ability to curtail output in response to an ISO dispatch instruction, either due to physical or contractual limitations. This will provide these variable energy resources with a three year transition period to resolve their contractual issues and enhance their systems to enable such resources to participate in the ISO markets more effectively. The ISO believes that the protective mechanisms should be limited to three years to ensure that the entire market realizes the benefits of the real-time market design after a suitable transition period.

The ISO respectfully requests that the Commission issue an order by February 13, 2014 that accepts the proposed tariff revisions effective April 1, 2014.[4] Approval of the instant filing will allow the ISO to comply with those aspects of Order No. 764 not addressed in the ISO's separate compliance filing.[5]

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[4] An effective date of April 1, 2014 will allow the ISO to include the market design changes embodied in the tariff revisions in the Spring 2014 release.

[5] The ISO is submitting a separate filing to comply with Order No. 764 tomorrow. That compliance filing addresses the meteorological and forced outage data requirements of Order No.

As explained below, an order by February 13, 2014 is needed to facilitate the proposed schedule for the implementation of new software and systems to enable the integration of the ISO's new energy imbalance market. The energy imbalance market design and software implementation plan are being built on the new fifteen-minute market and revised real-time market design and resulting software implementation proposed in the ISO's filing.

II. Background

A. The ISO's Existing Market Structure

1. The Current Hour-Ahead Scheduling Process and Real-Time Market

The market enhancements described in this filing are informed by experience with the ISO's current real-time market structure over the years since it was first implemented in 2009. Under the current design, the ISO administers both (1) an "hour-ahead scheduling process" (which also clears certain transactions in the hour-ahead time frame) and (2) the real-time market, which together are sometimes referred to as the ISO's "dual real-time market structure." This dual real-time market structure results in separate settlement of prices in the current hour-ahead scheduling process and the current real-time market. The ISO adopted this "separate settlement" structure in the real-time to accommodate hourly transmission schedules, which were and are required by existing market coordination rules that obligate balancing authority areas within the Western Interconnection to schedule intertie transactions (*i.e.*, transactions between balancing authority areas) on an hourly basis.[6]

The ISO's current real-time market software conducts four runs every hour that look ahead four to seven 15-minute intervals to perform real-time unit commitment. The runs also provide "real-time pre-dispatch" functionality, establishing financially non-binding energy schedules and financially binding ancillary services awards for transactions at internal nodes, *i.e.*, transactions conducted inside the ISO balancing authority area.[7] Within each of these 15-

764. In that filing, the ISO seeks leave to comply with the intra hour scheduling requirements of Order No. 764 through the instant filing.

[6] Under the current rules, except for dynamically scheduled resources, intra-hour changes are scheduled between balancing authority areas in the Western Interconnection only in the event of contingencies or to address transmission overloads.

[7] In this filing, transactions conducted at internal nodes are sometimes referred to as internal transactions, and the resources that engage in them are sometimes referred to as internal resources. Similarly, in this filing transactions conducted on interties are sometimes referred to as intertie transactions and the resources that engage in them are sometimes referred to as intertie resources.

minute periods, the current real-time market also performs real-time dispatch of resources for three five-minute dispatch intervals.[8] Another process, the ISO's "short-term unit commitment" process, runs every hour to commit short- and medium- start units and looks ahead three hours beyond the period covered by this process.

This real-time pre-dispatch functionality of the real-time unit commitment runs is also currently used as part of the hour-ahead scheduling process to establish financially binding energy schedules and ancillary services awards on an hourly (60-minute) basis for transactions on the interties, *i.e.*, hourly imports to and exports from the ISO balancing authority area.[9] Specifically, the current hour-ahead scheduling process is an hourly run of the real-time unit commitment process used to issue hourly pre-dispatch instructions to system resources (*i.e.*, resources located outside of the ISO balancing authority area) that submit energy bids in the real-time market and to award ancillary services for dispatched system resources on an hourly basis. The hour-ahead scheduling process also permits scheduling coordinators to self-schedule changes to their day-ahead schedules and to submit bids to export energy at scheduling points.[10] Each run of the current hour-ahead scheduling process begins 75 minutes before the relevant trading hour.[11]

The real-time unit commitment process uses security constrained unit commitment and security constrained economic dispatch to optimize the commitment, scheduling, and dispatch of resources. The real-time dispatch uses security constrained economic dispatch to determine optimal dispatch instructions to balance supply and demand.[12]

Today, the hour-ahead scheduling process and the real-time market result in different locational marginal prices for purposes of financial settlement.[13] Four

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[8] See tariff section 34.2. The real-time unit commitment process does not dispatch resources but rather, as discussed above, performs advisory pre-dispatch of resources.

[9] As explained below, the tariff revisions proposed in this filing result in a new hour-ahead scheduling process that is limited to scheduling intertie resources that are settled at prices established through the fifteen minute market.

[10] See tariff sections 33, 34.2.

[11] See tariff appendix A (current definition of "hour-ahead scheduling process") (*i.e.*, the definition of this term before the changes proposed in this filing).

[12] See tariff sections 27.4, 33, 34. During contingency conditions, different dispatch rules apply. See tariff section 34.3.

[13] As discussed below, issues with this "separate settlement" structural component of the dual real-time market structure compelled the ISO to discontinue convergence bidding on the interties effective November 28, 2011 and has continued to cause revenue imbalances in the ISO

15-minute locational marginal prices are calculated for the next trading hour and those four prices are averaged to produce hourly locational marginal prices for the settlement of intertie schedules for energy and ancillary services awards over the interties on an hourly basis. In today's real-time market, the real-time dispatch calculates five-minute locational marginal prices for internal resources for each five-minute dispatch interval.[14] Real-time market settlement occurs on a 10-minute basis using the average of two consecutive five-minute locational marginal prices.[15]

2. Eligible Intermittent Resources and Participating Intermittent Resource Program

The resources that take part in the ISO markets include those powered by wind or solar energy. These are called eligible intermittent resources under the existing ISO tariff.[16]

Eligible intermittent resources are subject to many of the tariff provisions discussed above that apply to other types of resources taking part in the hour-ahead scheduling process and real-time market. However, the tariff also includes a number of provisions that recognize the distinctive operating characteristics of eligible intermittent resources. Those provisions address the process for forecasting, scheduling, and settling the output of an eligible intermittent resource and for settling deviations between the resource's scheduled and actual output.

The ISO schedules eligible intermittent resources that take part in the ISO's participating intermittent resource program in the real-time market based on an hourly aggregated forecast of their expected output that is posted approximately 90 minutes before the applicable trading hour and fixed for that entire hour.[17] This scheduled output is treated as instructed imbalance energy and is settled in each hour at the average five-minute locational marginal price for the hour.[18] Deviations between a participating intermittent resource's

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markets.

[14] See tariff sections 27.1.1, 33.8, 34.3.1.

[15] *See, e.g.*, *California Independent System Operator Corp.*, 116 FERC ¶ 61,274, at P 529 (2006). Settlement of instructed imbalance energy is performed using a weighted average of the prices and settlement of uninstructed imbalance energy is performed using a simple average of the prices. *See* ISO tariff sections 11.5.1, 11.5.2.

[16] See tariff appendix A (definition of "eligible intermittent resource").

[17] See tariff section 6.5.12.

[18] See tariff section 11.5.1.

scheduled and actual output are treated as uninstructed imbalance energy but are netted over each month, and the net deviation for the month is settled at the weighted average of the five-minute locational marginal prices for the month, where the weights are the metered generation quantities associated with each five-minute locational marginal price.[19]

The ISO established the participating intermittent resource program to provide an option for integration of eligible intermittent resources (now more commonly referred to as variable energy resources) into the ISO's markets. An eligible intermittent resource that meets specified technical standards may elect to participate in the program by becoming a participating intermittent resource. Alternatively, an eligible intermittent resource may elect to be scheduled and settled in the same manner as non-variable energy resources, and is not required to seek certification as a participating intermittent resource.

The participating intermittent resource program was an appropriate approach to address the limited ability of many variable energy resources to respond to dispatch instructions and to address the design of the ISO's market at the time the program was developed.

3. Convergence Bidding on the Interties and Real-Time Imbalance Energy Offset Issues

In addition to submitting bids or schedules for physical resources and demand, ISO market participants can also hedge their market positions and manage their exposure to the differences between day-ahead and real-time prices by submitting purely financial bids – called virtual bids in the ISO tariff.[20] If a market participant's virtual bid is cleared in the day-ahead market, it is automatically liquidated with the opposite buy/sell position at the real-time price.[21] One of the main expected benefits of convergence bidding is to improve the convergence of day-ahead and real-time prices in the ISO's markets.[22]

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[19] See tariff sections 11.5.2, 11.12.1, 11.12.4, 34.19.2.5; tariff appendix Q section 5.2.

[20] See tariff section 30.9. The terms "virtual" and "convergence" are used interchangeably in this filing to refer to those types of bids and transactions.

[21] See tariff section 11.3.

[22] *See, e.g.*, *California Independent System Operator Corp.*, 130 FERC ¶ 61,122, at P 35 (2009) ("Nodal convergence bidding provides benefits that have been well-documented by the Commission. We have found that convergence bidding can . . . improve day-ahead and real-time price convergence . . ."); *California Independent System Operator Corp.*, 133 FERC ¶ 61,039, at P 14 (2010) ("The Commission has found that convergence bidding reduces the price differences between the real-time and the day-ahead markets.").

The ISO implemented convergence bidding on February 1, 2011 at both internal nodes and the interties.[23] The Commission approved position limits on the megawatt volume of virtual bids that any one scheduling coordinator could submit at an individual node or intertie, in order to address the potential exercise of market power or unintended market consequences during the initial period of convergence bidding implementation.[24] Although the convergence bidding design included a number of features to address potential market manipulation and avoid adverse market impacts, the Commission recognized that it was just and reasonable to implement the position limits as an additional safety net to prevent unforeseen and unintended market outcomes.[25] The Commission found that use of more cautious and longer-lasting position limits on the interties was justified because, "by pushing more activity into the HASP [hour-ahead scheduling process], there could be increased reliability concerns due to an increased reliance on resource adequacy resources and the transactions being closer in time to when the energy is required."[26]

Soon after convergence bidding went into effect, two issues arose with convergence bidding on the interties, despite the position limits and other measures approved by the Commission to address potential market power and adverse market consequences. The first and most significant issue was that convergence bidders were able to take advantage of the real-time bifurcated settlement structure, *i.e.*, the use of different locational marginal prices in the hour-ahead scheduling process for intertie pricing points and the real-time market for internal pricing points for purposes of financial settlement. Actual market data showed that the separate settlement structure was inhibiting the intended market efficiencies associated with convergence bidding on the interties and causing adverse impacts on the market through an increase in market uplifts and the distortion of market prices.

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[23] *See id.* at PP 1, 253.

[24] *See id.* at PP 121-29.

[25] *Id.* at P 121. The other market design features intended to help stop potential market manipulation and adverse market activity included measures to deter implicit convergence bidding, *i.e.*, scheduling of physical bids in the day-ahead market with no intention of physically delivering on the schedules, for the purpose of liquidating the schedules in the hour-ahead scheduling process. *See id.* at PP 134; ISO tariff sections 11.32, 11.8.6.6. Another such market design feature was the use of two constraints (a physical and also a physical and virtual constraint) within its market software in the day-ahead market for each intertie scheduling point after convergence bidding went into effect. *See* 130 FERC ¶ 61,122, at PP 66-67; tariff section 31.8.

[26] 133 FERC ¶ 61,039, at P 125. Further, the Commission found, "given the total size of transactions at the interties, additional caution is justified." *Id.*

The real-time imbalance energy offset is a real-time neutrality account used to reconcile settlement dollar values for all real-time energy charge codes for all energy bought and sold in the real-time market to ensure that, after all payments and charges have been calculated, there is neither a shortage nor a surplus in revenue. Surpluses or shortages are allocated to scheduling coordinators based on a pro rata share of their measured demand (*i.e.*, metered load and exports).

The ISO had experienced real-time imbalance energy offset charges that were higher than expected since the implementation of its current market design in April 2009. The ISO subsequently identified differences between hour-ahead scheduling process prices and real-time dispatch (five-minute) prices as the main cause of the offset costs.

In February 2011, when the ISO implemented convergence bidding, it anticipated that virtual bids would help to improve price convergence and thereby to reduce real-time imbalance energy offset charges. But contrary to the ISO's expectations, after convergence bidding went into effect, price divergence between hour-ahead scheduling process prices and real-time prices increased, and therefore the offset charges also increased.

The ISO determined that the bifurcated settlement structure had made it consistently profitable for market participants – individually and collectively – to submit virtual bids for supply on interties that were offset by virtual demand bids at locations within the ISO. Virtual bids for sales on the interties are settled at the hour-ahead scheduling process price, while the internal bids for purchases are settled at the real-time dispatch price. As a result, when the virtual bids on the interties were cleared against the internal bids, and the hour-ahead scheduling process price was less than the real-time dispatch price – as it frequently was – the real-time imbalance energy offset incurred a charge that was allocated to scheduling coordinators.

The second and less significant issue that arose with convergence bidding on the interties was that the use of two software constraints (a physical and also a physical and virtual constraint) in the day-ahead market periodically caused market clearing prices on the interties to be inconsistent with the bid prices offered by a physical exporter or importer. This second issue was separate from and unrelated to the first issue discussed above.

4. Stakeholder Initiatives Addressing Intertie Issues and Suspension of Convergence Bidding on the Interties

The ISO addressed aspects of the market inefficiencies described above in a number of stakeholder initiatives. First, in 2009, the ISO initiated a stakeholder process called Real-Time Imbalance Energy Offset that culminated

in the Commission's acceptance of tariff revisions to exempt the load and exports of load-following metered subsystems from the allocation of real-time imbalance energy offset charges.[27]

In April 2011 the ISO initiated two stakeholder processes to identify potential solutions to the two issues with convergence bidding on the interties discussed above.[28] After combining the two convergence bidding-related initiatives and considering various alternative proposals, the ISO concluded that discontinuing convergence bidding on the interties was justified, at least until a comprehensive market redesign stakeholder initiative could permit the ISO to address issues related to the existing design of the hour-ahead scheduling process and real-time market.[29]

In the course of a renewable integration stakeholder process, the ISO also discussed with stakeholders the potential redesign of the real-time market to a 15-minute interval dispatch and a new balancing product, such as a one-minute granularity dispatch, to manage changes between the 15-minute dispatch and regulation. However, the ISO and stakeholders concluded that it would be unlikely that neighboring balancing authorities in the Western Electricity Coordinating Council ("WECC") region would be able to accommodate 15-minute scheduling in the next two to three years. Also, the implementation complexity of the 15-minute dispatch design would not be achievable in two to three years due to significant software changes required for implementing the new balancing product that was considered at one point as an alternative to the current real-time dispatch market.

On September 21, 2011, the ISO filed a tariff amendment requesting authorization to discontinue convergence bidding on the interties effective as of November 28, 2011. The Commission, in an order issued on November 25, 2011, accepted and suspended the tariff amendment for a nominal period, effective November 28, 2011 as requested by the ISO, and made its acceptance subject to the outcome of a technical conference and further Commission order.[30] At the February 2012 technical conference, the ISO provided further

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[27] Commission letter order, Docket No. ER09-1781-000 (Nov. 9, 2009).

[28] The first of the initiatives begun in April 2011 was called Real-Time Imbalance Energy Offset (2011), and the second initiative was called Price Inconsistency Caused by Intertie Constraints.

[29] As explained below, after issuance of Order No. 764, the ISO decided to address the comprehensive market redesign related to intertie pricing issues as part of its stakeholder initiative to address compliance with Order No. 764 – the stakeholder initiative that resulted in the filing of this tariff amendment.

[30] *California Independent System Operator Corp.*, 137 FERC ¶ 61,157 (2011).

documentation that supported discontinuing convergence bidding on the interties. The ISO supplied additional evidence in comments filed after the technical conference.[31]

On May 2, 2013, the Commission issued an order conditionally accepting the ISO's proposal to discontinue intertie convergence bidding.[32] The Commission found that the ISO "should focus its efforts on developing a comprehensive, long-term structural solution that will permit the reinstatement of intertie convergence bidding with just and reasonable outcomes, improving market efficiency by committing supply resources to meet real-time needs."[33]

The Commission noted that the ISO had "suspended its existing stakeholder proceeding on intertie pricing and settlement [*i.e.*, the Renewable Integration Market and Product Review Phase 2 stakeholder process] and alternatively [had] chose[n] to address intertie settlement issues in a new stakeholder initiative that will also address compliance with Order No. 764."[34] The Commission stated that, to the extent the proposal developed in that stakeholder initiative also included proposed tariff revisions that address the issues raised in the proceeding on intertie virtual bidding but were outside the immediate scope of Order No. 764, the ISO "should include these proposed tariff revisions in a FPA section 205 filing."[35]

The Commission required that, within 12 months of the issuance of the May 2 order, the ISO must either: "(1) file tariff changes to reinstate convergence bidding and address the underlying issues with the existing dual real-time market structure [*i.e.*, the separate settlement structure], or (2) submit an informational filing explaining why CAISO has not addressed the dual real-time market structure issues and cannot reinstate intertie convergence bidding at that time."[36]

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[31] In the meantime, in late 2011, the ISO had established a new stakeholder initiative, called Intertie Pricing and Settlement, to determine long-term solutions to address the real-time imbalance energy offset and pricing inefficiencies between the hour-ahead scheduling process and the real-time market identified during the two initiatives established in April 2011. During this stakeholder effort, the ISO considered alternatives to address the intertie pricing issues, but this effort ultimately was superseded by the Order No. 764 stakeholder process.

[32] *California Independent System Operator Corp.*, 143 FERC ¶ 61,087 (2013) ("May 2 order").

[33] *Id.* at P 61. The Commission expressly declined to direct or express guidance on a specific design proposal. *Id.* at P 72.

[34] *Id.* at P 74.

[35] *Id.*

[36] *Id.* at P 76.

The instant filing is submitted in accordance with the first alternative afforded by this directive.

B. Order No. 764

On June 22, 2012, the Commission issued Order No. 764 to adopt reforms that would remove barriers to the integration of variable energy resources and provide for related just and reasonable rates.[37] Specifically, the Commission required each public utility transmission provider – including the ISO – to make two revisions in a compliance filing:

(1) Revise its open access transmission tariff to include prescribed provisions that give customers the option of using intra-hour transmission scheduling at 15-minute intervals;[38] and

(2) Revise its *pro forma* large generator interconnection agreement to include prescribed provisions that define variable energy resources and require new interconnection customers whose generating facilities are variable energy resources to provide meteorological and forced outage data to the public utility transmission provider for the purpose of power production forecasting.[39]

The Commission declined to require tariff revisions in addition to the intra-hour scheduling mandates of the Order, but provided each transmission provider an opportunity to demonstrate on compliance that its existing tariff provisions or alternative intra-hour scheduling proposals are consistent with or superior to the Order No. 764 requirements.[40]

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[37] Order No. 764 at P 1.

[38] *Id.* at PP 97, 113, 373-74, Appendix B. The requirement to implement 15-minute transmission scheduling only applies to intertie transactions in organized wholesale energy markets like the ISO markets. *Id.* at P 113.

[39] *Id.* at PP 171, 210, 373, 375, Appendix C.

[40] *Id.* at PP 98 n.128, 106-07, 374; Order No. 764-A at P 39. With regard to the directives in Order No. 764 on the reporting of meteorological and forced outage data, the Commission recognized that transmission providers in some regions have already implemented provisions addressing such reporting in their existing tariffs, business practices, and/or market rules. The Commission explained that transmission providers subject to the "independent entity variation" standard set forth in Order No. 2003 could seek to demonstrate in their compliance filings how continued use of those provisions in their existing tariffs, business practices, or market rules was adequate to satisfy the requirements of the independent entity variation standard. Order No. 764 at PP 194, 197, 375.

The Commission also clarified that the first requirement of Order No. 764 applies to scheduling practices, not to imbalance settlement or sub-hourly dispatch.[41] The Commission directed that, to the extent a transmission provider believes it should align imbalance settlement with the intra-hour scheduling interval or should implement sub-hourly dispatch, it may propose those revisions in an FPA section 205 filing submitted either at the same time as its Order No. 764 compliance filing or at such other time it deems appropriate.[42]

The Commission directed that filings to comply with Order No. 764 would be due by November 12, 2013.[43] On October 18, 2013, the Commission granted a motion for extension of time filed by the ISO to permit it to submit its Order No. 764 compliance filing by November 27, 2013.

C. Stakeholder Process for Order No. 764 Market Enhancements

After Order No. 764 was issued in June 2012, the ISO recognized that the requirement in the Order to provide an option for 15-minute schedules provided an incentive for public utility transmission providers in the Western Interconnection to move to more granular scheduling. To comply with Order No. 764, all Commission-jurisdictional balancing authorities in the WECC region, as well as some balancing authorities that are not Commission-jurisdictional balancing authorities, will be required to offer 15-minute scheduling and the ISO will need to accommodate such schedules on the interties.

The ISO initiated a new stakeholder process, called FERC Order No. 764 Market Changes, that addressed and thus subsumed the issues that were being discussed in the then-ongoing stakeholder proceeding on Intertie Pricing and Settlement. The purpose of this Order No. 764 stakeholder process was to develop tariff revisions to comply with the Order, including any proposals that are consistent with or superior to the Order's requirements.[44] The ISO concluded

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[41] *Id.* at P 104.

[42] *Id.* at P 105.

[43] Order No. 764-A at P 8. The Midcontinent Independent System Operator, Inc. ("MISO") submitted a filing to comply with Order No. 764 on August 23, 2013, as supplemented on August 27 and October 4, 2013. On October 22, the Commission accepted in part and rejected in part the MISO's proposed tariff revisions and required additional compliance changes by the October 22 deadline. *Midcontinent Independent System Operator, Inc.*, 145 FERC ¶ 61,064 (2013) On November 7, 2013, the Commission granted a motion for extension of time filed by the MISO to permit it to make a filing to comply with the Commission's October 22 order by December 27, 2013. Other public utility transmission providers submitted filings to comply with Order No. 764 on or around November 12, 2013.

[44] Materials regarding the stakeholder process to comply with Order No. 764 are available on the ISO website at http://www.caiso.com/informed/Pages/StakeholderProcesses/FERCOrderNo764MarketChanges.

that the Order No. 764 stakeholder process would provide an opportunity to more effectively and efficiently integrate a large amount of variable energy resources into the resource fleet serving ISO customers as well as to address ongoing concerns with intertie pricing.

The Order No. 764 stakeholder process was extensive and included a number of stakeholder meetings, workshops, and conference calls, opportunities for written stakeholder comments, papers issued by the ISO to develop the proposals contained in this filing, and revisions to the proposals based on stakeholder comments and the ISO's own review.[45] In the stakeholder process, the ISO sought to develop market design changes that are consistent with the following seven guiding principles:[46]

- Accommodation of new resource types based on their performance capabilities, without preference for specific technologies;
- Reliance on price signals to provide an incentive for market participant behavior that aligns with ISO operating needs;
- Encouragement of robust market participation;
- Ensuring an efficient mix of resources to maintain reliability and attract new investment when and where needed;
- Allowing easy adaptation to new and changing energy policy goals and mix of resources;
- Leveraging of existing ISO infrastructure, industry experience, and lessons learned; and

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aspx.

[45] A list of key dates in the stakeholder process is provided in attachment L to this filing.

[46] Two of the papers issued in the stakeholder process are provided in this filing for ease of reference. The first of these is entitled FERC Order 764 Compliance 15-Minute Scheduling and Settlement – Addendum to Draft Final Proposal (Apr. 24, 2013) ("addendum to draft final proposal"). The addendum to the draft final proposal is provided in attachment D to this filing and available on the ISO website at http://www.caiso.com/Documents/Addendum-DraftFinalProposal-FERC_Order764MarketChanges.pdf. The second paper is entitled FERC Order 764 Market Changes Intermittent Resource Protective Measures – Draft Final Proposal (Aug. 15, 2013) ("draft final proposal on protective measures"). The draft final proposal on protective measures is provided in attachment F to this filing and is available on the ISO website at http://www.caiso.com/Documents/DraftFinalProposal-FERCOrder764MarketChanges-IntermittentResourceProtectiveMeasures.pdf.

- Allocation of costs based on cost causation.[47]

Stakeholders generally recognized the benefits of the market enhancements proposed in this filing, and the ISO addressed issues they raised in the stakeholder process. The discussion below regarding the tariff revisions proposed in this filing addresses specific issues raised by stakeholders and the ISO's responses.

The ISO's Department of Market Monitoring ("DMM") and Market Surveillance Committee ("MSC") support the market enhancements proposed in this filing. The DMM worked closely with the ISO and stakeholders in developing the market design changes contained in the filing, which includes several key modifications made to address concerns identified by DMM.[48] The MSC stated its support for the key elements of the market design changes subject to analysis and monitoring of risks associated with the market design.[49] These risks and the steps the ISO will take to analyze and monitor them are discussed below.

At its May 15, 2013 meeting, the ISO Governing Board ("Board") approved all of the market design changes proposed in this filing other than transitional protective measures for intermittent resources, which were still under development at the time of that Board meeting.[50] The Board approved the protective measures at its September 12, 2013 meeting.[51]

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[47] Addendum to draft final proposal at 5-7.

[48] Memorandum from Eric Hildebrandt, Director of DMM, to ISO Governing Board (May 8, 2013) ("DMM memorandum"). The DMM memorandum is provided in attachment H to this filing and is available on the ISO website at http://www.caiso.com/Documents/DecisionFERC_Order764_MarketDesignChanges-DMM%20Comments-May2013.pdf.

[49] Final MSC Opinion on Order 764 Compliance and Related Market Design Changes (May 7, 2013) ("MSC opinion"). The MSC opinion is provided in attachment I to this filing and is available on the ISO website at http://www.caiso.com/Documents/DecisionFERC_Order764_MarketDesignChanges-MSC%20Opinion-May2013.pdf.

[50] The transitional protective measures for intermittent resources are discussed in section III(C)(3) of this transmittal letter.

[51] Materials related to the Board's May 15 and September 12 meetings are available on the ISO website at http://www.caiso.com/informed/Pages/BoardCommittees/BoardGovernorsMeetings.aspx. These materials include a Board memorandum for each of those meetings. The Board memorandum for the May 15 meeting ("May 8 Board memorandum") is provided in attachment E to this filing and is available on the ISO website at http://www.caiso.com/Documents/DecisionFERC_Order764_MarketDesignChanges-Memo-May2013.pdf. The matrix of stakeholder positions on the ISO's proposal presented at the May 15 meeting is provided as attachment M to this filing. The Board memorandum for the September

The day after submittal of the instant filing (*i.e.*, November 27), the ISO will submit a filing to comply with the requirements of Order No. 764. The instant filing submitted pursuant to FPA section 205 contains proposed tariff revisions that are consistent with or superior to the intra-hour scheduling requirements of Order No. 764, as well as related tariff revisions. The separate compliance filing addresses the meteorological and forced outage data requirements of Order No. 764. In that filing, the ISO also seeks leave to comply with the intra-hour scheduling requirements of Order No. 764 through the instant filing.

III. Proposed Tariff Revisions

As discussed below, the ISO proposes to revise its real-time market design to align the scheduling and settlement of internal and intertie transactions with one another and with the directives in Order No. 764.[52] An overview of how the revised real-time market structure will work and a discussion of settlement and pricing issues related to the revised market design are provided in the attached declaration of Donald Tretheway, Lead Market Design and Regulatory Policy Specialist for the ISO.[53] The ISO also proposes to reintroduce convergence bidding on the interties. Matters regarding intertie convergence bidding are discussed in the attached declaration of Gregory Cook, Director of Market Design and Regulatory Policy for the ISO.[54] In addition, the ISO provides a matrix that describes briefly the reasons for the changes to each tariff section that is being revised in this filing and the reasons for the new tariff sections proposed in the filing.[55]

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12 meeting ("September 5 Board memorandum") is provided in attachment G to this filing and is available on the ISO website at http://www.caiso.com/Documents/Decision-FERC_Order764MarketChanges-Memo-Sep2013.pdf.

[52] Some of the tariff revisions contained in this filing build upon the tariff revisions proposed in the ISO's pending filing in Docket No. ER13-2452 to implement phase 1 of the ISO's renewable integration market and market review enhancements. Also, this filing includes revisions to appendix N to the ISO tariff. When the ISO was preparing those revisions, it discovered that, due to an administrative error made in the eTariff records submitted in the original proceeding in which appendix N was accepted for filing (Docket No. ER11-4161), the eTariff record on file does not accurately reflect the clean and marked tariff provisions in that proceeding, but rather is comprised of another, unrelated tariff appendix. In order to faithfully implement the intent of the Commission's order accepting appendix N for filing, the correct clean text of appendix N has been used in this filing, and the eTariff record submitted in this filing reflects that correct accepted language, as modified by the revisions proposed in this filing.

[53] Mr. Tretheway's declaration is provided in attachment J to this filing.

[54] Mr. Cook's declaration is provided in attachment K to this filing.

[55] The tariff matrix is provided in attachment C to this filing.

A. Changes to the Design of the Hour-Ahead Scheduling Process and Real-Time Market

1. Implementation of the Fifteen-Minute Market and a Limited Function for the New Hour-Ahead Scheduling Process

The ISO proposes to enhance the existing design of the hour-ahead scheduling process and real-time market. The cornerstone of the revised market structure is that financially binding 15-minute prices for energy and ancillary services will now apply to all internal transactions and to all transactions of market participants that choose to schedule on the interties on a 15-minute basis. This fundamental feature of the revised market structure is called the *fifteen-minute market*, or FMM for short. The fifteen-minute market will be an additional real-time market feature and will be an interval of the existing 15-minute interval granularity real-time unit commitment process. It will be conducted throughout the operating day for each 15-minute interval after the corresponding hour-ahead scheduling process and prior to the corresponding real-time dispatch, in order to clear bids for energy and ancillary services from internal supply, imports and exports, and the ISO forecast of ISO demand.[56] Both internal and intertie transactions will also have financially binding 15-minute schedules, although market participants will also have the option of scheduling intertie transactions on an hourly basis. The fifteen-minute market will produce 15-minute locational marginal prices and ancillary services prices, at which all resources will be settled.[57]

The fifteen-minute market will leverage the existing real-time unit commitment process. That process currently creates binding real-time commitment decisions and produces 15-minute energy schedules. Today, the 15-minute energy schedules produced by the real-time unit commitment process are advisory financially non-binding schedules for internal resources and are also used for financially binding schedules for imports and exports as part of the hour-ahead scheduling process. The real-time unit commitment process also produces financially binding 15-minute ancillary services awards. This real-time unit commitment process runs approximately every 15 minutes at regular intervals. The ISO is proposing to modify the existing process to produce financially binding scheduling and settlement of energy schedules for both resources situated in the ISO balancing authority area and external resources bidding and scheduling energy on the interties through the fifteen minute market.

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[56] The ISO proposes to add the new term “fifteen-minute market” to appendix A to the tariff, to define it as described above, and to make revisions throughout the tariff to reference the fifteen-minute market.

[57] See new tariff section 34.4; Tretheway declaration at 30.

The fifteen-minute market will align the market design for internal and intertie transactions and will allow internal and intertie resources to compete with one another and be priced on an equal 15-minute basis. Any imbalances, which are expected be minimal, will be settled at the five-minute real-time price. There will no longer be a separate and unique settlement for the interties. This will significantly reduce revenue imbalances previously allocated through real-time imbalance energy offset charges by eliminating those occurring due to the separate settlement structure for real-time under the ISO's current market design.

The ISO will be able to implement the fifteen-minute market and other components of the revised market design using its existing market functionality. This will greatly reduce implementation complexity, time, and costs. In addition, use of the fifteen-minute market for both internal and intertie transactions is consistent and superior to the requirement in Order No. 764 that market participants must have the option of using intra-hour transmission scheduling at 15-minute intervals for intertie transactions, because it increases the efficiency of the ISO's real-time market.

Further, the MSC explained that while the introduction of 15-minute scheduling will pose some operational challenges for the ISO and adjacent balancing authority areas, the experiences of other independent system operators ("ISOs") and regional transmission organizations ("RTOs") indicates that those challenges should be manageable.[58] PJM Interconnection, LLC ("PJM") has permitted 15-minute changes of price-taking intertie transactions with adjacent balancing authority areas for over a decade. PJM and the MISO have also managed large volumes of price-taking 15-minute schedule changes for approximately eight years. Moreover, the New York Independent System Operator, Inc. ("NYISO") implemented price-based scheduling of 15-minute transactions with Hydro-Québec in 2011 and with PJM in 2012. Thus, as the MSC explained, "the California ISO is not entering uncharted waters in implementing 15 minute scheduling; this is something that other ISOs and RTOs have been able to manage and the California ISO should be able to successfully implement."[59]

The MSC also found that 15-minute interchange (*i.e.*, intertie) transactions will have the following potential benefits for the ISO and its market participants: better alignment of interchange levels with known intra-hour demand and supply

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[58] MSC opinion at 3.

[59] *Id.* The MSC went on to state that the ISO could successfully implement 15-minute scheduling if given flexibility in the timing and manner of implementation. *Id.* The tariff revisions proposed in this filing will give the ISO the needed flexibility.

changes; better alignment of the level of imports with actual load levels; more flexibility for the ISO to use adjustments in net interchange to accommodate changes in variable energy resource output and other changes in supply that cannot be anticipated in the hour-ahead scheduling process; and better matching of the level of imports to the level of demand.[60]

Pursuant to the revised market structure, the real-time market will include not only the fifteen-minute market but also retain the existing real-time unit commitment and short-term unit commitment processes,[61] and will also include a revised version of the hour-ahead scheduling process. Specifically, the new hour-ahead scheduling process will establish binding intertie schedules only for market participants that elect to submit self-scheduled hourly blocks and for economic bids that the market participant desires to clear at a fixed hourly quantity. It will determine these schedules through a co-optimization process that includes advisory schedules for variable energy resource interchange transactions and 15-minute economic bids.[62]

The new hour-ahead scheduling process will also determine advisory schedules for 15-minute offers over the four 15-minute intervals of each hour, although the fifteen-minute market will determine final 15-minute intertie schedules for 15-minute offers.[63]

The ISO proposes to provide the following six bidding and scheduling options to market participants transacting on the interties:

(1) Self-scheduled hourly block;

(2) Self-scheduled variable energy resource forecast;

(3) Economic bid hourly block;

(4) Economic bid hourly block with a single intra-hour schedule change;

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[60] *Id.* at 5-6.

[61] *See* existing tariff sections 34.2 and 34.4; the ISO proposes to retain these provisions in revised tariff sections 34.3 and 34.6.

[62] See new tariff section 34.2; tariff appendix A (revised definition of "hour-ahead scheduling process"); Tretheway declaration at 25-28.

[63] See new tariff section 34.2.2.. *See also* MSC opinion at 8.

(5) Economic bid with participation in the fifteen-minute market (which may or may not be linked to a variable energy resource forecast); and

(6) Dynamic transfer.

The various forms of scheduling allow scheduling coordinators to transition towards fifteen minute scheduling while continuing to provide options for hourly block schedules. In addition, these options are designed to minimize seams with other balancing authority areas as they transition towards more granular scheduling over time. These hourly intertie bidding and scheduling options are discussed in more detail in section III(B)(1) below.

The current hour-ahead scheduling process will no longer establish binding prices for intertie resources and will become purely a scheduling process for fixed hourly inter-tie schedules that establishes these schedules while reserving intertie capacity for forecasted variable energy resource interchange transactions. Therefore, the ISO proposes to eliminate the details of tariff section 33 and incorporate the new hour-ahead scheduling process as part of the real-time market procedures in tariff section 34. The ISO will also retain the five-minute dispatch process used for dispatching internal resources.

2. Elements of the Revised Market Design

As is the case today, all bids, which include economic bids and self-schedules for energy and ancillary services, both at the interties and at internal locations, will continue to be submitted from the time the day-ahead market results are posted up to 75 minutes prior to the applicable trading hour. Bids into the fifteen-minute market must be submitted for all internal and external transactions at this same time.[64] The results from the hourly process to accept fixed block schedules (described below) will be published 45 minutes before the start of the applicable hour.[65] The fifteen-minute market will begin 37.5 minutes before each 15-minute interval and will send the results to market participants 22.5 minutes before that interval.[66]

The purpose of this timing is to initiate the software run in as short a time as possible prior to the 15-minute interval while also allowing the ISO to maintain consistency with the deadline required by the WECC for submitting e-tags for

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[64] See revised tariff section 30.5.1(a).

[65] See revised tariff section 6.5.4.1.5; new tariff section 34.2.4.

[66] See revised tariff section 34.4.

intertie transactions, which is 20 minutes prior to the operating interval.[67] These enhancements will result in a significant reduction in lead time for scheduling variable energy resources and thus a reduction in renewable energy forecast error through use of a more current forecast. These enhancements will also lead to more optimal intertie scheduling because the 37.5-minute lead time will be much less than the current hour-ahead scheduling process' 75-minute lead time.[68]

Notwithstanding the other market design enhancements, internal resources will continue to be dispatched on a five-minute basis, as they are today. The five-minute dispatch will consider forecasts received from variable energy resources 7.5 minutes in advance.[69] Each variable energy resource will be dispatched based on their corresponding forecast.

The fifteen-minute process will also schedule resources to be delivered over the interties between the ISO and neighboring balancing authority areas. The intertie resources will be scheduled on a 15-minute basis or, for resources that choose one of the hourly options described below, on an hourly basis that applies a single quantity to all four 15-minute blocks within the hour.[70]

For internal transactions, the settlement interval will be changed from 10 minutes to five minutes.[71] Any differences between the 15-minute schedules and day-ahead schedules for internal (and intertie) transactions will be settled at the 15-minute prices. Any differences between the 15-minute schedules and metered output for internal transactions, and any differences between the 15-minute schedules for intertie transactions and 15-minute energy schedules on e-tags, will be settled at the five-minute price.[72]

Under the revised market design, a variable energy resource will have the option to use the ISO forecast or its own forecast for scheduling and settlement purposes. In order to be initially certified to use its own forecast, a variable

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[67] *See* reliability standard INT-008-3 at 6-7, available on the website of the North American Electric Reliability Corporation ("NERC") at http://www.nerc.com/files/INT-008-3.pdf. *See also* Tretheway declaration at 16-17.

[68] Additional detailed information regarding the revised market design and figures illustrating the market design are provided in Mr. Tretheway's declaration at pages 11 to 34.

[69] See revised tariff section 34.5.

[70] See revised tariff section 34.4.

[71] See tariff appendix A (revised definition of "settlement interval").

[72] See revised tariff section 11.5.2.2. Settlement of intertie transactions is discussed further below.

energy resource will need to demonstrate that it has the ability to successfully submit a forecast to the ISO's scheduling infrastructure business rules ("SIBR") system. The ISO will compare its forecast with the variable energy resource's forecast over time to determine which forecast is more accurate. The ISO will also look for instances of strategic forecasts to exploit differences between 15-minute and five-minute prices. The ISO will rescind the ability of a variable energy resource to use its own forecast if the resource's forecast is significantly less accurate than the ISO forecast over time.[73]

The market design changes will not significantly affect the ability of resources to dynamically transfer power into or out of balancing authority areas. Market participants will continue to have the option to establish dynamic transfer arrangements that enable five-minute dispatch and settlement of intertie transactions. These will have new 15-minute schedules like internal generation and will be settled similar to internal generation.[74]

Under the revised market design, inter-scheduling coordinator trades will remain an hourly product and will be settled at the simple average of the four fifteen-minute market locational marginal prices for the hour.[75]

Participating load, proxy demand resources, and other dispatchable demand response will continue to be able to participate in the 15-minute market and real-time dispatch, but load serving entities and non-participating load will not be able to do so.[76] This is because, as described below, load will continue to clear based on ISO forecast demand, just as it does under the current market design.

For load that is metered hourly, differences in load from day-ahead schedules will be settled at the hourly weighted average of the 15-minute and five-minute prices by default load aggregation point. The prices will be weighted by the megawatts cleared in the 15-minute and five-minute market runs.[77]

Load that is not metered hourly – *i.e.*, load following metered subsystems – will be settled in a manner similar to how it is settled under the current market design. In the fifteen-minute market, load following metered subsystems will need to balance their load and supply. In the real-time dispatch, load following

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[73] See new tariff section 4.8.2.1; Tretheway declaration at 51.

[74] See Tretheway declaration at 11.

[75] See revised tariff sections 11.9.1, 28.1.2.

[76] See revised tariff section 34.20.1; Tretheway declaration at 43.

[77] See revised tariff section 11.5.2.2; Tretheway declaration at 41-42.

subsystems must balance their load supply in the five-minute interval within the established threshold or else be subject to deviation penalties.[78]

3. The ISO Has Addressed Issues Raised During the Development of the Revised Market Design

a. The ISO Will Monitor for and Address Deviations from Dispatch Instructions and Forecasts

Regarding the changes to the design of the hour-ahead scheduling process and real-time market, some stakeholders suggested that separately settling the 15-minute market schedules and the five-minute real-time dispatch may provide an incentive for resources to deviate from ISO dispatch instructions to arbitrage prices between the two markets. They suggested that this could consist of an intertie transaction not delivering the amount dispatched in the 15-minute market or an internal generator deviating from its five-minute real-time dispatch. A related concern raised by stakeholders is that a variable energy resource potentially could generate profits for itself by manipulating its forecast used for the 15-minute market to create differences with its five-minute real-time dispatch.[79]

The ISO responded that these concerns were not warranted because the five-minute real-time dispatch price will appropriately value the cost of undelivered schedules. Further, in situations where the five-minute real-time price will not apply to a schedule produced by the hour-ahead scheduling process because that undelivered schedule is subsequently reduced to zero MWh by the fifteen-minute market, the ISO proposes to apply an intertie schedules decline charge (which will be similar to the ISO's existing decline charge) to the undelivered schedule.[80] Nonetheless, the ISO committed to monitor for deviations that potentially could be used to exploit differences between 15-minute and five-minute prices and is prepared to propose deviation penalties in the future even for internal resources, if appropriate. In addition, the revised tariff provisions will allow the ISO to require a variable energy resource to use the ISO's forecast if a resource persistently submits forecasts with excessive errors.[81]

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[78] See new tariff sections 11.5.1, 11.5.2; tariff appendix A (new definitions of "FMM MSS Price" and "RTD MSS Price"); Tretheway declaration at 42-43.

[79] May 8 Board memorandum at 10.

[80] See revised tariff section 11.31; new tariff section 30.5.1(r); Tretheway declaration at 21, 39-41. The intent of the intertie schedules decline charge is to penalize energy schedules that are not delivered or variable energy resource forecasts that are over-stated but do not otherwise incur a financial obligation in the market for the undelivered energy. Tretheway declaration at 40.

[81] See new tariff section 4.8.2.1; Tretheway declaration at 51.

b. The Revised Market Design Addresses e-Tagging Concerns

Some stakeholders raised the concern that issuing intertie dispatches for the 15-minute scheduling intervals at 22.5 minutes before the start of the interval, when updates to the energy portion of e-tags are due 20 minutes before the start of operating interval, might afford little time for market participants to update the e-tags for schedule changes within the hour. Stakeholders also expressed the related concern that some unforeseen mechanical seams issue could arise with an adjacent balancing authority that does not accommodate 15-minute scheduling, making 15-minute scheduling of intertie interchange impractical.[82]

As noted above, the issuance of dispatches as soon as possible prior to the 15-minute interval is a beneficial feature of the revised market design because it will allow the ISO to use the most current forecast for renewable generation and load and will maximize the accuracy of the market results. In response to this specific concern, the ISO will update the energy schedule portion of e-tags to reflect changes to schedules between 15-minute market intervals, which will expedite approval of an e-tag update by another balancing authority area.[83] The ISO performing this update, as opposed to requiring market participants to initiate the update of e-tags to reflect 15-minute schedule changes, should enable these e-tag updates to occur despite the tight timeline.

The ISO systems will automatically update energy schedules on e-tags to facilitate participation in the fifteen-minute market on the interties. However, in providing this automated service, the ISO will not assume any responsibility or liability related to the e-tagging rules as they apply to transactions on the Western Interconnection. It will ultimately be the responsibility of each scheduling coordinator to ensure that an energy schedule on an e-tag reflects the delivered quantity and that the e-tag complies with all applicable rules. Therefore, scheduling coordinator will be able to override the automated update of the energy schedule on the e-tag and change it after the ISO systems perform the automated update.[84]

Pursuant to the applicable e-tagging rules, balancing authorities have an additional 10 to 15 minutes (depending on whether the change is at the top of an

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[82] May 8 Board memorandum at 10.

[83] To avoid confusion with the existing term “Schedule” as defined in tariff appendix A, the proposed tariff revisions contained in this filing refer to energy schedules on e-tags as “energy profiles.”

[84] See new tariff section 30.6.2.

hour or within an hour) to confirm the e-tag changes before initiating the ramp for the schedule change.[85] The ISO's discussions with neighboring balancing authorities confirm that they are making changes to accommodate 15-minute schedule changes.[86]

c. The Revised Market Design Does Not Change Transmission System Modeling

One stakeholder asked for clarification as to how the ISO will account for loop flow in the new hour-ahead scheduling process and enhanced real-time market. The ISO's filing does not change the ISO's existing approach to modeling the transmission system, which was accepted by the Commission prior to the start-up of the ISO's current markets.[87]

d. The Revised Market Design Will Likely Reduce Overall Uplift

The MSC stated that, while settling intertie transactions at 15-minute prices determined closer to real-time should tend to reduce uplift costs (*i.e.*, real-time energy imbalance offset costs) relative to the existing market design, settling internal generation and load deviations from day-ahead schedules at 15-minute prices and then settling deviations from 15-minute schedules at five-minute prices will give rise to new uplift costs. The MSC anticipated that the net effect of these changes will likely be a reduction in overall uplift costs relative to the current design.[88]

The ISO agrees with the MSC that the net effect of the proposed changes will likely be to reduce overall uplift on the ISO system. The proposed changes will eliminate the potential for uplift due to pricing differences between the current

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[85] *See* reliability standard INT-008-3 at 6-7.

[86] May 8 Board memorandum at 11.

[87] *See, e.g.*, *California Independent System Operator Corp.*, 123 FERC ¶ 61,285, at PP 121-22 (2008). The ISO anticipates that the existing approach to modeling the transmission system may be improved in the future based on the outcome of the ISO's ongoing stakeholder initiative called Full Network Model Expansion.

[88] MSC opinion at 15. The MSC also recommended that the ISO monitor the relationship between real-time pre-dispatch solutions and the real-time dispatch to minimize systematic and large random errors in order to achieve the intended benefits of the design changes. The MSC further recommended that the ISO promptly begin archiving real-time pre-dispatch data so that the relationship between real-time dispatch prices and the real-time pre-dispatch prices that will be used for settlements is understood by the ISO and its stakeholders well before the new settlement design is implemented. *Id.* The ISO will take the MSC's recommendations into account and has already begun archiving such data.

hour-ahead scheduling process and the real-time dispatch under the current separate settlement structure.

The DMM stated that high real-time imbalance energy offset charges can also result from differences in congestion prices and flows on interties between the day-ahead and real-time markets. Thus, even with the proposed market design changes, significant real-time revenue imbalance energy charges can still occur if transmission limits are adjusted downward after the day-ahead market to account for unscheduled flows when congestion occurs. This creates offset costs by reducing the volume of energy flows in the real-time market over congested constraints. The DMM stated that it will remain important for the ISO to continue efforts to improve modeling of flows in the day-ahead and real-time markets, so there will be less need to reduce flows in real-time by adjusting constraint limits.[89]

The ISO recognizes that real-time congestion offset is an issue that should be examined, but notes that nothing in the fifteen-minute market proposal will exacerbate it. The ISO and stakeholders will have a full opportunity to address concerns about real-time congestion offset in the separate stakeholder initiative the ISO has established regarding Full Network Model Expansion.

B. Market Design Changes Specific to Intertie Transactions

1. Bidding and Scheduling Options for Intertie Transactions

As explained above, the ISO proposes to revise the design of the hour-ahead scheduling process and real-time market so that both internal and intertie transactions can be scheduled and settled on a 15-minute basis. However, the ISO recognizes that some market participants may not move as quickly from hourly to 15-minute scheduling for their intertie transactions.

The ISO proposes to provide market participants that transact on the interties with the bidding and scheduling options discussed below.[90] Pursuant to these options, market participants will have a variety of choices for taking part in intertie transactions on either a 15-minute or an hourly basis. The ISO does not intend to eliminate any of these options in the future but does anticipate that market participants will use certain of these options less over time as use of 15-minute scheduling and economic bidding becomes more widespread elsewhere in the West. The proposed intertie bidding and scheduling options will facilitate

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[89] DMM memorandum at 4.

[90] See new tariff sections 30.5.1(q)-(u), 34.1.3, 34.2.1, 34.2.2; Tretheway declaration at 19-23.

this transition while still allowing the ISO to address the inefficiencies with the current real-time market design.

Making these options available to market participants under the revised market design is consistent with or superior to the requirements of Order No. 764, which did not include options to ease the transition of market participants to the market changes required by the Order.

The ISO notes that the new intertie bidding and scheduling options will facilitate the delivery of variable energy resources on the interties. When determining the amount of fixed hourly schedules to accept on an intertie, the new hour-ahead scheduling process will reserve intertie capacity for the maximum amount of variable energy resource schedules forecast for all 15-minute intervals in the hour.[91]

a. Options for Scheduling Intertie Transactions on a 15-Minute Basis

Market participants will have the option to submit economic bids that the ISO can schedule in 15-minute intervals based on the bid components. These transactions will be settled at the 15-minute locational marginal price. The intertie bids will be cleared in the same optimization as internal resource bids. Consequently, intertie and internal resources will be able to compete and be priced on an equal basis.

Similarly, market participants will have the option to schedule the output of their variable energy resources to be delivered over the interties in 15-minute intervals based on their forecast output. These intertie transactions will be settled at the 15-minute price, just like intertie transactions involving conventional resources scheduled on a 15-minute basis. The scheduling and settlement of variable energy resources is discussed in more detail further below. Market participants will also have the option to take part in dynamic transfers on a 15-minute basis.

Providing these 15-minute bidding options to conventional and variable energy resources will satisfy the directive in Order No. 764 to give customers the option of using intra-hour transmission scheduling at 15-minute intervals for intertie transactions in organized wholesale markets.

The ISO will provide bid cost recovery for market participants that exercise the option to submit economic bids that the ISO can schedule in 15-minute intervals and for market participants that exercise the dynamic transfer option,

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[91] See new tariff section 34.2.1.

but as discussed below, the ISO will not provide bid cost recovery for market participants that exercise any of the other options for scheduling intertie transactions.

b. Options for Scheduling Intertie Transactions on an Hourly Basis

Market participants will also have a number of options for transacting on the interties on an hourly basis.

First, market participants will have the option to submit self-schedules for intertie transactions that are fixed for the hour. These self-schedules will be settled at the four 15-minute prices over the hour.

Market participants will also have the option to submit economic bids for intertie transactions that will be a fixed quantity for the hour and that the ISO can schedule based on price. The ISO will schedule these intertie transactions based on prices projected using the new hour-ahead scheduling process but will settle the transactions at the actual 15-minute prices over the operating hour. Schedules under this fixed economic bid option that turn out to be uneconomic (*i.e.*, do not recover the market participants' as-bid costs) will not be eligible for bid cost recovery.

Not permitting bid cost recovery under this option is appropriate for a number of reasons. An important goal of the revised market design is to encourage import suppliers and export buyers to submit flexible 15-minute bids. This goal would be undermined if bid cost recovery were to be paid on hourly transactions to import suppliers. Significantly, if bid cost recovery were allowed under this option, market participants might submit offsetting hourly and 15-minute schedules that would generate net revenues when hourly prices were greater than 15-minute prices.[92] This is because, for example, an import would be guaranteed a higher price while the charge for an export in the 15-minute market could be lower than the clearing price projected by the hour-ahead scheduling process.

In this regard, the DMM explained that providing bid cost recovery for imports and exports using this hourly scheduling option would essentially reinstate the same "bid or better" settlement rules for hourly intertie schedules under the ISO's prior market design that led to over $33 million in uplift costs from the time those settlement rules were implemented in 2004 until they were changed in 2005 pursuant to the filing of an ISO tariff amendment. Those uplift costs inevitably result when real-time prices are either higher or lower than the

[92] MSC opinion at 7.

projected or advisory prices used to clear the market. A very large portion of the $33 million in uplift costs was paid for offsetting import and export bids (by the same or different market participants) that provided no net energy to the ISO system.[93]

Further, not permitting bid cost recovery under the economic bid option is consistent with the approach taken by the NYISO in implementing 15-minute scheduling. Before it introduced price-based 15-minute scheduling on external interfaces two years ago, the NYISO settled price-based intertie transactions at real-time prices and paid bid cost recovery for economically scheduled transactions that did not recover their offer prices at real-time prices. But as the NYISO has implemented price-based 15-minute scheduling over the past two years, it has eliminated its bid production cost guarantee for hourly transactions at external interfaces.[94]

In addition, the ISO recognizes that a market participant choosing the fixed economic bid option will expose itself to the risk that the 15-minute prices the ISO pays for an import may end up being lower than the prices projected by the new hour-ahead scheduling process that were used to clear the market participant's fixed hourly import bid. However, the market participant can compensate for this risk by increasing its bid price. Conversely, as the market participant may potentially pay more than its bid price for exports, the market participant presumably will lower its bid price for fixed hourly exports. This effect on the prices of fixed hourly intertie transactions is appropriate and desirable, for two reasons: (1) it will transparently price the additional cost of fixed hourly schedules rather than allocate this cost to an uplift charge as is currently done, and (2) it will appropriately value fixed hourly intertie transactions relative to the greater value of 15-minute dispatchable intertie transactions.

Another option that will be available to market participants is a variant on the fixed hourly economic bid option. Scheduling and settlement will work the same way under the variant, except that the market participant will be able to change its schedule once per hour if the 15-minute prices meet criteria specified by the market participant. For example, under this variant scheduling option, the ISO would reduce an import schedule to zero if the 15-minute price for the balance of the hour decreased below the price specified by the market participant. Resources exercising this option will not be eligible for bid cost recovery, for the reasons discussed above and also because the market participant's ability to change its schedule once per hour eliminates the risk of exposure to locational marginal prices below the resource's bid price if system

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[93] DMM memorandum at 3.

[94] See NYISO filing in Docket No. ER11-2547-000 (Dec. 28, 2010). The Commission accepted this filing in *New York Independent System Operator, Inc.*, 134 FERC ¶ 61,186 (2011).

conditions change between the hour-ahead scheduling process and the financially binding fifteen-minute market.

Any variable energy resources that routinely submit high forecasts to the hour-ahead scheduling process will be subject to the intertie schedules decline charge, because their submission of high forecasts will displace other intertie resources. The decline charge or the five-minute price, depending on the circumstances, will also be applied to other intertie schedules that are not delivered.[95]

2. The ISO Has Addressed Issues Raised During the Development of the Bidding and Scheduling Options for Intertie Transactions

a. The ISO Will Continue to Monitor and Analyze Its Markets and Will Be Able to Address Any Issues with Market Liquidity

Although many stakeholders support this aspect of the ISO's proposal, some stakeholders claimed that the ISO's proposal only to guarantee bid prices of intertie transactions on a 15-minute basis and not to guarantee the price for hourly schedules will conflict with the western bilateral energy markets, which are currently oriented around hourly energy and transmission purchases. The stakeholders stated that the conflict could result in less liquidity and higher prices on the interties. Stakeholders were concerned that market participants may engage in fewer real-time intertie transactions with the ISO and will incorporate a high risk premium into offers for hourly energy on the interties.[96]

The ISO responded that the move to a 15-minute energy market over the interties is necessary to reliably integrate renewable resources and is consistent with Order No. 764. The bilateral markets throughout the West will inevitably evolve to transact energy on a 15-minute basis to balance variable energy resources' schedule changes. The ISO's approach accommodates hourly intertie schedules while also creating economic incentives to bid energy on a 15-minute basis, which will provide a proper valuation of hourly and 15-minute intertie schedules.[97]

The MSC stated its support for this key element of the market design changes, subject to analysis and monitoring of risks associated with the market

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[95] See new tariff section 11.31(c); Tretheway declaration at 21, 41.

[96] May 8 Board memorandum at 9.

[97] *Id.* at 9-10.

design.[98] The MSC raised three concerns. These concerns and the steps the ISO will take to monitor for and analyze them are discussed below.

The MSC noted there will not necessarily be a liquid supply of 15-minute intertie bids and offers when the market design changes first are implemented. If this is the case, the MSC stated, uncertainty regarding the impact of implementing these changes could lead to somewhat higher offer prices for import supply. Further, it should be anticipated that the overall elasticity of import supply in real-time, for both hourly and 15-minute transactions, may, at least initially, be somewhat lower than under the current design. The MSC noted that there will, however, be offsetting benefits in the form of reduced costs from uneconomic import and export transactions. The MSC stated that the ISO will need to monitor the relationship between prices projected in the new hour-ahead scheduling process and binding real-time pre-dispatch prices and make any changes needed to maintain price convergence, in order to help maintain the elasticity of import supply.[99]

Risks of price divergence can be addressed in market participant bidding behavior. The ISO recognizes, however, that price convergence among integrated forward market process, hour-ahead scheduling process advisory prices, fifteen-minute market prices, and real-time dispatch prices will reduce the risk premium and thus benefit all market participants. The ISO will monitor the performance of the new hour-ahead scheduling process, and will perform market analysis and validation on a regular basis, just as it does today for the existing hour-ahead scheduling process. The ISO will take appropriate steps if this market analysis and validation raises significant price divergence concerns under the new market design.

As explained above, when determining the amount of fixed hourly schedules to accept on an intertie, the new hour-ahead scheduling process will reserve intertie capacity for the maximum amount of variable energy resource schedules forecast for all 15-minute intervals in the hour. The MSC stated that if the supply of 15-minute intertie bids and offers is initially not very liquid, allowing output-contingent intermittent offers to displace fixed hourly import schedules may contribute to the volatility of 15-minute and five-minute prices. The MSC stated that this potential can be studied prior to implementation and managed by the way the ISO forecasts variable energy resource output for the hour-ahead scheduling process.[100]

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[98] MSC opinion at 14-15.

[99] *Id.* at 15.

[100] *Id.*

Variable energy resources will continue to have an incentive to provide forecasted schedules that are not overstated, because overstated schedules will be subject to the intertie schedules decline charge.[101] As the volume of variable energy resource transactions on the interties increases over time, the increased volume should diversify the variations in forecasts noted by the MSC, thereby reduce unused intertie capacity due to variable energy resource variations and reduce the risk of price volatility. If an increased volume of variable energy resources does not reduce their variation over the interties, it should still further incent 15-minute balancing energy to be marketed in the West.

b. The Revised Market Design Will Retain the Ability for a Variable Energy Resource to Use Its Own Forecast in Scheduling on the Interties

The DMM stated that hourly transmission capacity reserved for variable energy resources will either become financially binding or released for other resources in the fifteen-minute market. However, this has the potential to allow transmission reservations for variable energy resources to displace intertie resources with fixed hourly schedules and consequently could be used as part of a manipulative strategy to limit intertie capacity. Therefore, the DMM recommended that the ISO retain its authority to utilize its own forecast of the output of variable energy resources if schedules submitted by those resources appear to be systematically inaccurate and create detrimental market impacts.[102]

As discussed above, the ISO proposes that any variable energy resources that routinely submit high forecasts to the hour-ahead scheduling process will be subject to penalties and rescission of the ability to use their own forecasts rather than the ISO's.[103]

C. Market Design Changes Specific to Variable Energy Resources

1. Order No. 764 Compliance Changes

In its separate filing to comply with Order No. 764, the ISO proposes to modify its tariff to include the certain revisions related to variable energy resources that are required by Order No. 764.[104]

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[101] Tretheway declaration at 21, 41.

[102] DMM memorandum at 5.

[103] See new tariff sections 4.8.2.1, 11.31(c); Tretheway declaration at 21, 41, 51.

[104] *See* Order No. 764 at PP 171, 210, 373, 375, Appendix C.

As an initial matter, the term eligible intermittent resource in the ISO tariff is limited to resources that are powered by wind or solar energy. Order No. 764 applies to a somewhat broader group of renewable resources, defining a "variable energy resource" as:

> a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. This includes, for example, wind, solar thermal and photovoltaic, and hydrokinetic generating facilities.[105]

In its compliance filing, the ISO proposes to modify the definition of an eligible intermittent resource to align it with the new term "variable energy resource" as defined in Order No. 764. In the instant filing, the ISO proposes to revise the tariff to conform with these definitional changes.[106]

Second, in the compliance filing, the ISO proposes to revise the *pro forma* large generator interconnection agreement under appendix EE to its tariff to include the provisions set forth in Order No. 764 that require interconnection customers whose generating facilities are variable energy resources to provide meteorological and forced outage data to the ISO for the purpose of power production forecasting.

2. Scheduling and Settlement of Variable Energy Resources

In the instant filing, the ISO proposes tariff revisions to seize the opportunity provided by Order No. 764 to create a market structure oriented around variable energy resources. The addition of 15-minute scheduling and settlement will provide a framework superior to the existing market design for scheduling variable energy resources and will provide incentives for those resources to reduce their output in response to grid conditions as signaled by market prices. As explained in the ISO's separate Order No. 764 compliance filing, this market design is consistent with or superior to the intra-hourly scheduling requirements of Order No. 764 because, within the context of the ISO's markets, these market design enhancements not only satisfy the minimum intra-hourly scheduling requirements of the Order but actually go further to remove barriers to the integration of variable energy resources and "to allow for

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[105] *Id.* at P 1 n.1.

[106] See tariff appendix A section (revised definition of "Eligible Intermittent Resource" and new definition of "Variable Energy Resource").

the more efficient utilization of transmission and generation resources to the benefit of all customers."[107]

Internal and dynamically scheduled variable energy resources will be scheduled on a 15-minute basis using resource-specific rolling multi-hour forecasts with five-minute granularity. Specifically, the 15-minute schedules for these resources will be based on the average of the relevant three five-minute-interval forecasts of their output that are generated 37.5 minutes prior to each 15-minute interval – the same lead time applicable to scheduling of conventional resources.[108] This scheduling of variable energy resources will provide significant benefits. First, it will provide a 15-minute forecast to be scheduled in the market, which will improve upon the current hourly forecast for variable energy resources. Second, the forecast lead time will be shortened substantially from the current lead time of approximately 90 minutes, and the forecast will be updated four times per hour rather than being fixed for the hour as is the case under the current market design. Further, it is anticipated that the 15-minute price will be less volatile than the five-minute price previously applied to the output forecast for the hour, greatly reducing variable energy resources' exposure to price volatility.[109]

Also, the current market design does not include a mechanism for dispatching down the output of variable energy resources in the real-time market based on economic bids. The revised market design will improve upon this situation by permitting a variable energy resource to submit economic energy bids so that the resource can be dispatched to a level less than its maximum forecast output in either the 15-minute or five-minute market if the locational marginal price is less than the resource's bid.[110] A variable energy resource that submits such a bid will thereby signal its willingness to be curtailed in system over-generation conditions. This feature will be important when prices are negative due to over-generation conditions, because under those conditions, resources are charged for their energy production.

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[107] See Order No. 764 at P 5.

[108] See new tariff sections 4.8.2.1, 34.1.6; Tretheway declaration at 49-50.

[109] Tretheway declaration at 48-49, 51-54. As described above, under the revised market design, a variable energy resource will have the option to use the ISO forecast or its own forecast. The ISO will determine which forecast is more accurate and will rescind the ability of a variable energy resource to use its own forecast if the resource's forecast is significantly less accurate than the ISO forecast over time.

[110] See new tariff sections 4.8.2.1, 34.1.6; Tretheway declaration at 49-50. The ISO originally contemplated proposing to implement this economic bidding mechanism in the fall of 2013, prior to implementation of the other tariff revisions proposed in this filing. *See* May 8 Board memorandum at 8. However, due to implementation concerns, the ISO subsequently determined that it should propose making all of the tariff revisions effective as of the same date – April 1, 2014.

Permitting this submission of economic energy bids will provide significant benefits for both variable energy resources and the ISO's ability to maintain system reliability. Variable energy resources can maximize their participation in the market by responding to price signals. In doing so, they can either avoid exposure to unfavorable real-time market prices or be paid to curtail their output in the fifteen-minute market if they have day-ahead schedules or in the real-time dispatch if they have fifteen-minute market schedules. Submitting economic bids will also make variable energy resources eligible for bid cost recovery. Bid cost recovery shields variable energy resources from real-time price risk by guaranteeing that they will not be charged an amount greater than their bid prices for instructed imbalance energy in the five-minute dispatch.

The ISO proposes a number of revisions with regard to the settlement of variable energy resources. Instead of settling the scheduled output of a variable energy resource in each hour at the average five-minute locational marginal price for the hour, as is the case under the current participating intermittent resource program in the ISO tariff, the forecast-based scheduled amounts will be settled in each 15-minute interval at 15-minute locational marginal prices.[111] This settlement methodology will permit the prices to be determined on a more granular (15-minute versus 60-minute) basis. In addition, these 15-minute schedules will be based on forecasts 37.5 minutes prior to real time which is a significant improvement over the current design that uses hourly schedules based on a forecast 90 minutes prior to real-time under the participating intermittent resource program. Further, it will align the settlement methodology applicable to variable energy resources with the 15-minute settlement of conventional resources under the revised market design.

In addition, the revised market design includes more granular settlement of deviations from the scheduled output of variable energy resources. Deviations from the 15-minute forecasts and five-minute dispatches will be instructed imbalance energy and will be settled at five-minute market locational marginal prices.[112] Differences between the five-minute dispatch and the metered energy will be uninstructed imbalance energy and will be settled at five-minute market locational marginal prices.[113]

Under the existing tariff, imbalances from hourly schedules of participating intermittent resources are netted over the month and settled at the average

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[111] See revised tariff section 4.8.1; Tretheway declaration at 49-50.

[112] See revised tariff section 11.5.1.

[113] See revised tariff section 11.5.2.

monthly five-minute price.[114] This is an accommodation of the current market design to mitigate real-time price risk, because deviations from the hourly forecast can be significant.

However, it is just and reasonable to remove this netting option under the revised market structure. Deviations by variable energy resources will be substantially reduced as a result of being measured against more accurate and up-to-the-minute forecasts and more granular 15-minute schedules. Further, in the stakeholder process, the ISO analyzed actual market data to compare the existing settlement provisions applicable to variable energy resources with the revised settlement provisions proposed in this filing. The analysis showed that the vast majority of variable energy resources would have received more real-time market revenues under the revised market design than they do currently.[115] For these reasons, the ISO proposes to eliminate netting of imbalances over the month for participating intermittent resources, subject to certain transition provisions described in the following section.[116]

3. Protective Measures for Certain Variable Energy Resources

Although it is anticipated that most variable energy resources will be better off under the revised market structure, some owners of older variable energy resources asserted that they could be disadvantaged under the revised market structure because of their resources' inability to respond to dispatch instructions. In response, the Board directed ISO management to investigate whether limited protective measures to address that issue would be appropriate. ISO management investigated and determined that it was appropriate to develop the transitional protective measures discussed below, which were approved by the Board at its September 2013 meeting.[117]

The protective measures proposed in this filing will provide variable energy resources utilizing older technology or having power purchase agreements that explicitly prohibit them from voluntarily responding to real-time

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[114] Today, eligible intermittent resources also have the option of foregoing this monthly netting and being settled in the same manner as non-intermittent resources.

[115] During the stakeholder initiative the ISO analyzed six representative resources. The analysis is available at http://www.caiso.com/Documents/Web%20conference%20May%201,%202013. In addition, the ISO has provided this analysis for additional resources at the request of those resources and their load serving entity counterparties.

[116] See revised tariff section 11.12.2; Tretheway declaration at 49-50.

[117] See Tretheway declaration at 54-59.

price signals with an optional three-year transition period so they can prepare to operate under the revised market structure.[118] The transition period will provide time for such resources, which might otherwise be unduly burdened by the revised market structure, to negotiate any necessary changes to their power purchase agreements. For qualifying facilities that will be reaching the end of their existing agreements established pursuant to the Public Utility Regulatory Policies Act ("PURPA"), the transition period will provide time for those variable energy resources to enter into new bilateral agreements for power purchases to manage their imbalance energy price risk.

To qualify for the protective measures, a variable energy resource must meet all of the following requirements:[119]

(1) Either (a) or (b) must be the case for the resource:

(a) More than 50 percent of the resource must be composed of technology that is unable to curtail output and cannot be made to do so without significant investment. Resources that lack only dispatch, control, and telemetry or metering that require upgrades to be able to respond will not qualify. Resources that require production facility investments such as turbine replacement would qualify.

(b) The resource is subject to an existing bilateral agreement for power purchases that is in effect when the measures become effective and that prohibits the resource from curtailing its output in response to an ISO dispatch (not including times when the resource is ordered to curtail its output by the ISO or an affected utility distribution company for reliability reasons).

(2) The owner of the resource must be responsible for real-time energy settlement, either under its existing bilateral agreement for power purchases or because the resource is not subject to any such bilateral agreement and thus is subject to real-time imbalance energy settlement in the ISO market. Any bilateral agreement for power purchases must specify that the resource is directly or indirectly subject to real-time imbalance energy settlement in the ISO markets.

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[118] Specifically, the transition period will be three years from the effective date of the tariff revisions contained in this filing to implement the market design changes, or until a new or amended bilateral agreement for power purchases is executed for the resource, whichever comes first. See new tariff section 4.8.3.3.

[119] See new tariff sections 4.8.3.1.2, 4.8.3.2.

(3) During the three-year term of the transition period, the resource owner must agree to engage in a good faith effort to address the existing contractual limitations, or the resource owner must engage in a good faith effort to upgrade the resource so that it can address the physical limitations.

(4) The resource owner must sign an affidavit certifying the resource meets all of criteria (1) thorough (3) above as appropriate. The ISO will not be testing resource to evaluate the validity of their statements. But the ISO will ask for authority to audit the parties for that limited purpose should the need arise.

The ISO proposes that variable energy resources that meet all the qualification requirements listed above must request to be subject to the transitional protective measures within 30 days of the effective date of the market design changes. Resources that qualify and select the settlement provisions applicable under the protective measures must remain under that settlement for the entire three-year transition period or until they enter into new bilateral agreements for power purchases, whichever comes first. The ISO will post on its website the requests received and the disposition of the requests.[120]

Variable energy resources that meet the qualification and timing requirements will be subject to a real-time market settlement under the new market structure that is similar to the existing settlement provisions applicable to participating intermittent resources. Specifically, a resource under the proposed protective measures will be settled as follows:[121]

- An hourly schedule will be settled using a 90-minute-in-advance forecast.

- The variable energy resource's hourly schedule based on its 90-minute-in-advance forecast will be settled at the simple average of the five-minute locational marginal prices.

- Deviations between the variable energy resource's actual energy output and the hourly schedule will be netted over each month. This amount will be settled at the output-weighted average of five-minute locational marginal prices over the month.

As is the case under the current tariff provisions, variable energy resources subject to settlement under the transitional protective measures will be

[120] See new tariff sections 4.8.3.1.1, 4.8.3.4.

[121] See new tariff section 11.12.1.

required to provide meteorological data for the independent forecast service provider to develop a resource-specific forecast. Therefore, qualifying facilities with contracts established pursuant to PURPA that currently do not provide meteorological data will be required to complete the variable energy resource certification process to be settled under the protective measures upon expiration of their contracts. Only after the certification process is completed will a variable energy resource be settled according to the proposed protective measures.

The difference between the real-time market settlement of any variable energy resource under the protective measures and the settlement that would have occurred under the proposed market design will be allocated in the same manner as under the settlement methodology currently applicable to variable energy resources, *i.e.*, to net negative deviations. This amount may be a payment or a cost to net negative deviations.[122]

To the extent a resource subject to the protective measures is contractually required to make use of the ISO's inter-scheduling coordinator trade for energy mechanism to effectuate payment transfers with its contractual counterparty, the scheduling coordinator may elect to flag the resource in the ISO's master file to indicate its election to settle any physical or converted physical inter-scheduling coordinator trades for energy at the resource's location. These inter-scheduling coordinator trades will settle at the hourly simple average of the real-time dispatch price of the pricing node at the affected resource's location, in contrast to settling at the 15-minute price at which inter-scheduling coordinator trades would otherwise settle. Financial inter-scheduling coordinator trades for energy will not be eligible for such treatment.[123]

The ISO anticipates that a comparatively small group of variable energy resources will seek to operate under the transitional protective measures. The ISO also recognizes that the protective measures and the associated cost allocation methodology described above will add incrementally to the complexity and costs of implementing the market design changes. However, due to the need to comply with Order No. 764 in a reasonable time frame and because the ISO does not believe it is appropriate to defer the many benefits of the market design enhancements, the ISO believes that the impacts on a relatively small group of resources should not lead to lengthy delays in implementing the market design enhancements. Therefore, while the ISO will strive to provide these financial adjustments soon after implementation of the revised market structure, the ISO may not have the systems ready to make these financial adjustments on the first day the enhanced market design is implemented. The settlement of resources under the protective measures will be trued up in later settlements

[122] See revised tariff section 11.12.2.

[123] See new tariff section 11.12.1.3.

after the market design changes are implemented. Any adjustments will be subject to the Commission interest rate, as already set forth in the ISO tariff.[124]

4. The ISO Has Addressed Issues Raised During the Stakeholder Process

a. There Is No Need to Allow Permanent Netting of Imbalances Under the Revised Market Design

Some stakeholders suggested that the ISO should maintain its existing tariff provisions that allow participating intermittent resources to net real-time energy imbalances over the month. In response, the ISO explained that market participants will not need the netting provision under the revised market design. First, variable energy resource forecasts will be generated 37.5 minutes prior to the start of the 15-minute market interval. In contrast, forecasts today are generated 90 minutes prior to the hour and do not change for the entire hour. Second, variable energy resources will receive a financial position in real-time in the 15-minute market, which should have less volatile prices than the 5-minute prices in real-time dispatch. Third, participating intermittent resources that have operational characteristics or contractual limitations that require the transitional protective measures will, as described above, be subject to additional protective energy settlement measures.[125]

The ISO has reviewed the market rules that apply to variable energy resources in other ISOs or RTOs. None of the other ISOs or RTOs have comparable provisions that allow variable energy resources to net real-time energy imbalances over the month. These provisions may have been appropriate at one point in time in the ISO's markets when these provisions facilitated the ISO's collection of meteorological data from variable energy resources. But in light of the subsequent changes in renewable generation technology, the increased role of variable energy resources in meeting the needs of customers in the ISO balancing authority area, and the directives in Order No. 764 requiring all variable energy resources to provide transmission providers with meteorological data, the ISO believes the long-term market design should not include such a netting mechanism.

b. The Proposed Transitional Protective Measures Are Appropriate

There was disagreement among stakeholders as to the appropriateness of providing transitional protective measures for variable energy resources that are

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[124] See existing tariff section 11.29.10.2.

[125] May 8 Board memorandum at 10.

composed of older technology.[126] For the reasons explained above, the ISO has determined that it is appropriate to provide these limited protective measures to such resources.

Some stakeholders argued that the protective measures may be ineffective in addressing the exposure of variable energy resources to the market design changes. In particular, stakeholders expressed concern that the eligibility requirements are unduly restrictive and the three-year duration of the protective measures will undermine their utility.[127]

As with all of the tariff revisions proposed in this filing, the proper legal standard to apply to the protective measures is whether the ISO's proposal – not any alternative proposal – is just and reasonable under section 205 of the FPA.[128] The eligibility requirements were designed through the stakeholder process to strike an appropriate balance between allowing variable energy resources composed of older technology to opt into the protective measures, while at the same time not making the protective measures so restrictive that such resources could not choose them. In addition, the Board directed that the eligibility requirements be modified to include variable energy resources that are subject to contractual rather than technological limitations on responding to ISO dispatch instructions. The ISO believes that three years should be a sufficient amount of time for variable energy resources to transition to the revised market structure. For all these reasons, the protective measures as proposed by the ISO are just and reasonable.

Stakeholders that are load serving entities questioned the need for the protective measures, given that the market design changes were developed to facilitate the integration of variable energy resources. The load serving entities supported a firm expiration date, limiting the program to resources physically unable to follow dispatches, and allowing eligible resources to fully opt into or opt out of the protective measures. However, they remained opposed to the features of the protective measures regarding cost allocation, expanding eligibility to resources that do not have a contract with a load serving entity, and allowing another request window.[129]

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[126] September 5 Board memorandum at 5.

[127] *Id.*

[128] *Calpine Corp. v. California Independent System Operator Corp.*, 128 FERC ¶ 61,271, at P 41 (2009). *See also New England Power Co.*, 52 FERC ¶ 61,090, at 61,336 (1990), *aff'd*, *Town of Norwood v. FERC*, 962 F.2d 20 (D.C. Cir. 1992) (rate design proposed need not be perfect, it merely needs to be just and reasonable), *citing Cities of Bethany, et al. v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984) (utility needs to establish that its proposed rate design is reasonable, not that it is superior to all alternatives).

[129] September 5 Board memorandum at 5.

Again, the proper legal standard to apply to the protective measures is whether the *ISO's* proposal is just and reasonable under section 205 of the FPA. The cost allocation provisions associated with the protective measures are the same cost allocation provisions that the Commission has already found to be just and reasonable under the participating intermittent resource program. It is reasonable to extend the existing cost allocation methodology to the protective measures because these protective measures are a transitional extension of the current participating intermittent resource program.

Lastly, the ISO believes it is important for the Commission to recognize that issues related to protective measures for participating intermittent resources are all financial settlement issues which can be resolved in the future through resettlements. As such, these issues should not be allowed to delay the implementation of the ISO's fifteen-minute markets or any corresponding delays in the ISO's energy imbalance market initiative.

D. Revisions to Reinstate Convergence Bidding on the Interties

Consistent with the direction provided by the Commission in the May 2 order accepting the ISO's tariff revisions to discontinue convergence bidding on the interties effective November 28, 2011, the ISO and stakeholders have developed a comprehensive, long-term structural solution that will permit the reinstatement of intertie convergence bidding with just and reasonable outcomes.[130] The tariff revisions to implement the structural solution are being submitted in this filing pursuant to FPA section 205, in accordance with the direction provided in the May 2 order.[131]

Under the market design enhancements, convergence bids at both internal nodes and the interties will be settled at the average of the four fifteen-minute market prices for the hour.[132] This structural solution will fully address the first and more significant issue that required convergence bidding on the interties to be discontinued: the existence of a separate settlement structure in real-time that settled intertie convergence bids based on the hour-ahead scheduling process but settled internal node convergence bids based on the five-minute

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[130] *See* May 2 order at P 61.

[131] *See id.* at P 74. As noted above, the May 2 order also required that, within 12 months of the issuance of the order, the ISO must either: (1) file tariff changes to reinstate convergence bidding and address the underlying issues with the existing dual real-time market structure, or (2) submit an informational filing explaining why the ISO has not addressed the dual real-time market structure issues and cannot reinstate intertie convergence bidding at that time. *Id.* at P 76. The ISO submits this filing consistent with the first alternative afforded by the May 2 order.

[132] See revised tariff sections 11.3.1, 11.3.2.

real-time dispatch price. This made it possible for market participants to profit by offsetting virtual supply bids on the interties and virtual demand bids at internal nodes, with the resulting price divergence and real-time imbalance energy offset charges described earlier in this filing. Once the separate settlement structure is supplanted by the revised market structure, it will no longer be profitable to offset the virtual supply and virtual demand bids. As a result, any price divergence and real-time imbalance energy offset charges formerly attributable to such offsetting will be eliminated.[133]

The structural solution will also address the second, less significant issue that supported discontinuing convergence bidding on the interties – the use of two software constraints (a physical and also a physical and virtual constraint) in the day-ahead market, which periodically caused market clearing prices on the interties to be inconsistent with the bid prices offered by a physical exporter or importer. The ISO proposes to address this issue by only enforcing in the integrated forward market the constraint that considers both physical and virtual intertie transactions.[134]

The ISO recognizes that enforcing only this constraint could result in physical schedules exceeding an intertie's capacity, since a virtual schedule can provide counter-flow to relieve congestion. Such an outcome could be problematic because the ISO must comply with WECC's requirement that transmission service providers accept e-tags only up to an intertie's capacity.[135] To prevent that outcome, the ISO proposes to accept e-tags in economic merit order of the cleared intertie bids up to an intertie's capacity. Any cleared intertie bids above that amount will not be allowed to e-tag prior to the start of the real-time market.[136] Since the real-time market does not consider virtual intertie schedules, the physical intertie schedules produced by the real-time market will always be within each intertie's capacity. Consequently, the ISO will be able to accept e-tags for all physical intertie schedules by WECC's real-time e-tag deadline of 20 minutes prior to the operating interval.[137]

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[133] See Cook declaration at 11-12.

[134] See new tariff section 31.8; Cook declaration at 12. The integrated forward market is the pricing run conducted by the ISO using security constrained unit commitment in the day-ahead market, after the market power mitigation process, which includes unit commitment, ancillary services procurement, congestion management, and energy procurement based on supply and demand bids. ISO tariff appendix A, definition of "integrated forward market."

[135] *See* reliability standard INT-006-3, requirement R1.2, available on the NERC website at http://www.nerc.com/files/INT-006-3.pdf.

[136] See new tariff section 30.6.2.

[137] *See* reliability standard INT-008-3 at 6-7; Cook declaration at 12-13.

Although the ISO anticipates that the proposed structural solution will address these two issues and permit a successful reintroduction of convergence bidding on the interties, the ISO is also mindful of the need to proceed carefully given the implementation of the other significant market design changes described above. The benefits of these market design changes are expected to be magnified when the ISO expands the real-time market to include other balancing authorities pursuant to the new energy imbalance market, which the ISO plans to implement in the fall of 2014.[138] As the MSC has noted, these benefits include: better alignment of interchange levels with known intra-hour demand and supply changes; better alignment of the level of imports with actual load levels; more flexibility for the ISO to use adjustments in net interchange to accommodate changes in variable energy resource output and other changes in supply that cannot be anticipated in the hour-ahead scheduling process; and better matching of the level of imports to the level of demand.[139]

Numerous stakeholders and the DMM raised significant concerns with implementation of convergence bidding on the interties at the same time the market is gaining experience with these other significant design changes. To address these concerns, the ISO proposes to implement the enhanced real-time market design set forth in this filing 12 months before the ISO reinstates convergence bidding on the interties.[140] This implementation schedule will allow the ISO and market participants to observe the operation of the fifteen-minute market under various seasonal conditions.

As another precautionary measure, the ISO proposes to phase in the reinstatement of convergence bidding on the interties through the use of gradually increasing position limits, which will limit the megawatt quantity of convergence bids that may be submitted by a scheduling coordinator to a specified percentage of the intertie transfer capability. Specifically, the ISO proposes the following schedule for phasing in the reinstatement of convergence bidding on the interties:[141]

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[138] Materials regarding the stakeholder process for the energy imbalance market are available on the ISO website at http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyImbalanceMarket.aspx.

[139] MSC opinion at 5-6.

[140] See Cook declaration at 13-14. Although convergence bidding on the interties will not be reinstated until 12 months after the other market design changes are implemented, the ISO requests that all of the tariff revisions proposed in this filing – including the tariff revisions to reinstate convergence bidding on the interties – go into effect as of April 1, 2014.

[141] See revised tariff section 30.7.3.6.3; new tariff section 30.7.3.6.3.2; Cook declaration at 14-16.

- Intertie position limits of 5 percent will apply for the first eight months after reinstatement of convergence bidding on the interties (*i.e.*, from April 1, 2015 to November 30, 2015).

- Intertie position limits of 25 percent will apply for the ninth through the twelfth months after reinstatement of convergence bidding on the interties (*i.e.*, from December 1, 2015 to March 31, 2016).

- Intertie position limits of 50 percent will apply for the thirteenth month through the sixteenth months after reinstatement of convergence bidding on the interties (*i.e.*, from April 1, 2016 to July 31, 2016).

- No intertie position limits will apply starting in the seventeenth month after reinstatement of convergence bidding on the interties (*i.e.*, August 1, 2016 and afterwards).

These percentages and time periods for the position limits applicable to the gradual reinstatement of convergence bidding on the interties are the same as the percentages and time periods that the Commission authorized when it approved the original implementation of convergence bidding on the interties.[142]

The Commission should find that these same percentages and time periods continue to be just and reasonable. Like the intertie position limits that were previously in effect, the position limits for the intertie convergence bidding proposed in this filing are intended to serve as an additional safety net to prevent unforeseen and unintended market outcomes.[143] Further, as the Commission previously found and events subsequently showed, it is appropriate for the ISO to be cautious by gradually implementing convergence bidding on the interties.[144] Additional caution is also justified given the total size of intertie transactions.[145] For these reasons, the Commission should approve the same percentage limits in order to smooth the transition to full reinstatement of convergence bidding on the interties.

One stakeholder contends that these position limits should be applied on a portfolio basis rather than applying an aggregate position limit applicable to all

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[142] *See* 133 FERC ¶ 61,039, at PP 95, 121-23,125-26, *reh'g denied*, 134 FERC ¶ 61,070, at PP 17-23 (2011).

[143] *See* 133 FERC ¶ 61,039, at P 121.

[144] *Id.*

[145] *Id.*

transactions on a given intertie. The ISO's approach, however, has previously been found to be just and reasonable by the Commission when it accepted intertie-specific position limits when convergence bidding was first implemented in the ISO's markets.[146]

In order to facilitate the return of convergence bidding on the interties, the ISO proposes to restore to the tariff the applicable provisions previously accepted by the Commission that the ISO removed in the tariff amendment to discontinue intertie convergence bidding.[147]

IV. Effective Date and Request for Waiver

The ISO respectfully requests that the Commission issue an order by February 13, 2014 that accepts all of the tariff revisions contained in this filing effective April 1, 2014. The ISO requests waiver of the Commission's notice requirement to permit this effective date.[148]

The ISO requests an order by February 13, 2014 in order to ensure that the schedule for implementing the market design changes set forth in this filing aligns with the schedule for implementing the ISO's new energy imbalance market, which will allow balancing authorities throughout the West to voluntarily participate in a real-time imbalance energy market operated by the ISO. The energy imbalance market is scheduled to become operational in October 2014. The energy imbalance market design and software implementation plan will build on the new fifteen-minute market and revised real-time market design proposed in the ISO's filing. The ISO determined that it would not be appropriate to develop the energy imbalance market based on the current real-time market design platform given the many benefits to market participants that will come with the new real-time market design.[149]

In addition, on September 25, 2013, the ISO filed proposed tariff revisions in Docket No. ER13-2452 to implement phase 1 of the ISO's renewable integration market and market review enhancements ("RIMPR 1") which includes the separation of bid cost recovery settlement between the day-ahead market

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[146] *Id.*, at PP 95-97, 125.

[147] See revised tariff sections 30.8, 30.9.

[148] Specifically, pursuant to section 35.11 of the Commissions regulations (18 C.F.R. § 35.11), the ISO requests waiver of the notice requirement contained in section 35.3 of the Commission's regulations (18 C.F.R. § 35.3) to allow the requested effective date. In its separate filing to comply with Order No. 764, the ISO also requests the same April 1, 2014 effective date for the tariff revisions proposed in that filing.

[149] See Cook declaration at 18-19.

and the real-time market. The energy imbalance market design is also dependent on Commission acceptance of this change. Significant changes to either the RIMPR 1 design proposal or the revised real-time market design proposal could potentially delay the implementation of the energy imbalance market by a year or longer.[150]

Issuance of an order by February 13, 2014 is also necessary to allow the ISO to make the system changes required to implement the revised market design six weeks later, on April 1.

Good cause exists for the Commission to grant waiver and permit the requested April 1, 2014 effective date. Granting this effective date will allow the market design changes to be included in the ISO's Spring 2014 release. For these reasons, the Commission should find that good cause exists to grant an effective date of April 1, 2014.

V. Communications

Correspondence and other communications regarding this filing should be directed to:

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VI. Service

The ISO has served copies of this filing on the California Public Utilities Commission, the California Energy Commission, and all parties with scheduling

[150] *See id.* at 19.

coordinator agreements under the ISO tariff. In addition, the ISO has posted a copy of the filing on the ISO website.

VII. Contents of this Filing

In addition to this transmittal letter, this filing includes the following attachments:

Attachment A	Clean ISO tariff sheets incorporating this tariff amendment
Attachment B	Red-lined document showing the revisions contained in this tariff amendment
Attachment C	Matrix of tariff revisions
Attachment D	April 24, 2013 addendum to draft final proposal
Attachment E	May 8, 2013 Board memorandum
Attachment F	Draft final proposal on protective measures
Attachment G	September 5, 2013 Board memorandum
Attachment H	DMM memorandum
Attachment I	MSC opinion
Attachment J	Declaration of Donald Tretheway
Attachment K	Declaration of Gregory Cook
Attachment L	List of key dates in the stakeholder process
Attachment M	Summary of comments submitted in the Order No. 764 stakeholder process

VIII. Conclusion

For the reasons set forth in this filing, the ISO respectfully requests that the Commission issue an order by February 13, 2014 that accepts the tariff revisions contained in this filing effective April 1, 2014.

Respectfully submitted,

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Attachment A – Clean Tariff Sheets

Real-Time Market Design Enhancements Related to Order No. 764

California Independent System Operator Corporation

November 26, 2013

4.5.3.12 Financial Responsibility

Assuming financial responsibility for all Schedules, AS Awards, and Dispatch Instructions issued in the CAISO Markets, and all Virtual Awards in accordance with the provisions of this CAISO Tariff; and

* * *

4.8 Relationships Between CAISO And Intermittent Resources

4.8.1 Bidding and Settlement

The CAISO shall not accept Bids for an Eligible Intermittent Resource other than through a Scheduling Coordinator. Any Eligible Intermittent Resource that is not a Participating Intermittent Resource, or any Participating Intermittent Resource for which Bids are submitted shall be bid and settled as a Generating Unit for the associated Settlement Periods (except that the Forecast Fee shall apply in such Settlement Periods). Scheduling Coordinators shall not submit Economic Bids for Participating Intermittent Resources that are subject to PIRP Protective Measures.

4.8.2 Forecasting

All Scheduling Coordinators for Eligible Intermittent Resources are subject to the forecasting requirements and the Forecast Fee as described below. All Eligible Intermittent Resources must provide the CAISO meteorological and outage data as specified in Appendix Q. Scheduling Coordinators for Variable Energy Resources not located in the CAISO Balancing Authority Area that elect to use the forecast provided by the CAISO are also subject to the Forecast Fee.

4.8.2.1 Forecast Requirements

4.8.2.1.1 Use of Own Forecast

For purposes of participating in the CAISO Markets, Eligible Intermittent Resource may opt to use their own forecast of their resource's output, and not use the forecast of their output provided by the CAISO, only to the extent the CAISO has certified that the Eligible Intermittent Resource has completed the certification requirements specified in the Business Practice Manuals. If the Eligible Intermittent Resources is certified to provide their own forecast, they must provide at a minimum a three-hour rolling forecast with fifteen- (15) minute granularity, updated every fifteen minutes, and may provide in the alternative a three-hour rolling forecast at five- (5) minute

granularity, updated every five minutes. If an Eligible Intermittent Resource opts to provide the forecast of their output at a five-minute granularity, the CAISO will use the average of the projected Energy output for the relevant three five (5)-minute forecasts to determine the Variable Energy Resource Self-Schedule for the Fifteen Minute Market as specified in Section 34. An Eligible Intermittent Resource that has elected to use its own forecast of its output must also submit the meteorological and outage data specified in Appendix Q. After the CAISO has certified an Eligible Intermittent Resource as eligible to provide its own output forecast, the CAISO may terminate the resource's certification if the CAISO determines that: (1) the Eligible Intermittent Resource's forecast is materially less accurate than the forecast provided by the CAISO on a regular basis; or (2) if the CAISO has a reasonable basis to believe that the resource is engaged in strategic forecasting for purposes other than accuracy. If the CAISO revokes the certification of an Eligible Intermittent Resource to use its own forecast, the Eligible Intermittent Resource must again complete the certification requirements specified in the Business Practice Manuals before it can again qualify to use its own forecast. For purposes of participating in the CAISO Markets, Participating Intermittent Resources may opt to use their own output forecast if they are certified to do so by the CAISO pursuant to the rules specified in the Business Practice Manuals, in which case: (1) the resource will retain its status as a Participating Intermittent Resource; (2) the CAISO will not submit the updated output forecast for that resource through the Real-Time Market; and (3) the resource will be subject to the same requirements that apply to Eligible Intermittent Resource that use their own output forecast as specified in the CAISO Tariff. Participating Intermittent Resources that are subject to PIRP Protective Measures are not eligible to opt to use a forecast of their output for purposes of participating in the CAISO Markets other than the forecast of their output provided by the CAISO.

4.8.2.1.2 Use of Forecast from Independent Forecast Provider

For purposes of participating in the CAISO Markets, Eligible Intermittent Resources have the option to use a forecast of their output provided by CAISO. Variable Energy Resources that are located outside the CAISO Balancing Authority Area may also elect to use the output forecast provided by the CAISO, provided that: (1) they agree to provide the CAISO with the

meteorological data specified in Appendix Q; and (2) they are certified to do so by the CAISO pursuant to the rules specified in the Business Practice Manuals. Once the election to use the output forecast provided by the CAISO is complete, the CAISO will specify the election status for the Eligible Intermittent Resource or the external Variable Energy Resource in the Master File. The Eligible Intermittent Resource and any Variable Energy Resource located outside of the CAISO Balancing Authority Area opting to use the forecast of their output provided by the CAISO, must provide the meteorological and outage data as specified in Appendix Q. Any changes to this election will be subject to the timeline and rule changes that apply to the Master File as specified in Section 30.7.3.2.

4.8.2.2 Application of the Forecast Fee

All Eligible Intermittent Resources are subject to the forecast fee specified in Section 2.4.1 of Appendix Q, regardless of whether the resource elects to use the CAISO-created forecast or relies on its own forecast. Variable Energy Resources located outside the CAISO Balancing Authority Area that elect to use the forecast of their output provided by the CAISO are also subject to the Forecast Fee specified in Section 2.4.1 of Appendix Q.

4.8.3 Transitional Protective Measures for Participating Intermittent Resources

4.8.3.1 Request for PIRP Protective Measures

4.8.3.1.1 Timing

Participating Intermittent Resources or Qualifying Facilities that wish to qualify for PIRP Protective Measures pursuant to Section 4.8.3.2 within the three-year transition period must complete their election for PIRP Protective Measures no later than thirty (30) days after the effective date of this Section 4.8.3.

4.8.3.1.2 Materials Submitted with Request

For a resource to qualify for PIRP Protective Measures, within thirty (30) days from the effective date of this Section, responsible parties must submit affidavits as described in either Section 4.8.3.1.2.1 or Section 4.8.3.1.2.2. The CAISO reserves the right to audit the representations made in the affidavits by giving written notice at least ten (10) Business Days in advance of the date that the CAISO wishes to initiate such audit, with completion of the audit occurring within 60

days of such notice. The audit shall be for the limited purposes of verifying that the Participating Intermittent Resource and counterparty to the relevant contract has represented the terms specified in the affidavit accurately. Upon request of the CAISO as part of such audit, the Participating Intermittent Resource or counterparty providing the affidavits specified below shall provide information to support its certification under Sections 4.8.3.1.2.1 or Section 4.8.3.1.2.2, as appropriate. Each party will be responsible for its own expenses related to any audit.

4.8.3.1.2.1 Physical Limitations

A Participating Intermittent Resource or Qualifying Facility requesting PIRP Protective Measures because of physical limitations, as specified in Section 4.8.3.2.2.1, must submit a sworn affidavit by a representative of the Participating Intermittent Resource or Qualifying Facility, who is authorized to bind the resource legally and financially . The affidavit must state that the resource meets the criteria specified in Section 4.8.3.2.1 and 4.8.3.2.2.1. The sworn affidavit must also state that the relevant party agrees that during the term of the three-year transition period, the party will engage in a good faith effort to upgrade the facility in order to address the limitations specified in Section 4.8.3.2.2.1.

4.8.3.1.2.2 Contractual Limitations

A Participating Intermittent Resource or Qualifying Facility requesting PIRP Protective Measures because of contractual limitations as specified in Section 4.8.3.2.2.2, must submit a sworn affidavit by a representative of the Participating Intermittent Resource or Qualifying Facility, who that is authorized to bind the resource legally and financially. The affidavit must state that the resource is subject to a contract that meets the criteria specified in Sections 4.8.3.2.1 and 4.8.3.2.2.2. The Participating Intermittent Resource or Qualifying Facility must serve their affidavit electronically to the counterparty to the applicable contract on the same day the affidavit is submitted to the CAISO. A representative of the counterparty to the applicable existing bilateral agreement that is authorized to legally and financially bind the counterparty may also submit a sworn affidavit stating that the resource is subject to a contract that meets the criteria specified in Sections 4.8.3.2.1 and 4.8.3.2.2.2. The counterparty must serve the affidavit electronically on the Participating Intermittent Resource or Qualifying Facility on the same day the

affidavit is submitted to the CAISO. Each party's respective affidavit must state that during the term of the three-year transition period, the party will engage in a good faith effort with the counterparty to address the existing contractual limitation specified in Section 4.8.3.2.2.2. In the event that the counterparty submits no affidavits within the thirty days, the CAISO deems the counterparty to have acquiesced to the request by the representative of the Participating Intermittent Resource, except if the Participating Intermittent Resource fails to serve the counterparty with the required documents within the prescribed time. If the counterparty later successfully demonstrates through a formal complaint filed at the Federal Energy Regulatory Commission that the Participating Intermittent Resource failed to serve the counterparty with the relevant materials as described in this Section, the CAISO will deny, and if appropriate reverse, any PIRP Protective Measures afforded to the requesting party. To the extent that the counterparty instead submits an affidavit by a representative of the company that is fully authorized to legally and financially bind the company stating that the resource's contract does not meet the criteria in Sections 4.8.3.2.1 and 4.8.3.2.2.2, the affidavit must also state that the Participating Intermittent Resource shall not suffer any economic or other repercussions under the contract and because of the terms of the contract were the resource to participate fully in the CAISO Market, including through the submission of Economic Bid for economic curtailment. The representative of the Participating Intermittent Resource may choose to withdraw its request in light of the counterparty's affidavit or pursue resolution of a contractual dispute through a dispute resolution process specified in the relevant contract, or if none is available, through the process specified in Section 13 of the CAISO Tariff, or through any dispute resolution process available through the Federal Energy Regulatory Commission. During the term that the contract is in dispute, the resource will be subject to PIRP Protective Measures provided it meets all the other criteria specified in this Section 4.8.3. Upon resolution of the dispute, if the dispute resolution process yields a conclusion that the contract is not eligible for PIRP Protective Measures, the resource will resume its status as a Participating Intermittent Resource not subject to PIRP Protective Measures. Unless, the parties together request the CAISO to reverse any previously

applied PIRP Protective Measures, the CAISO will not undo any prior Settlement of the PIRP Protective Measures.

4.8.3.2 Criteria

Participating Intermittent Resources or Qualifying Facilities that are registered as such on the day that this Section 4.8.3 becomes effective may qualify for PIRP Protective Measures if they meet the criteria specified below. Fulfilling such criteria is a requirement in addition to providing the affidavits described in Section 4.8.3.1.2. Qualifying Facilities whose capacity exceeds twenty (20) MW on the day this tariff section becomes effective may qualify if they meet the criteria specified below. Such Qualifying Facilities that elect and qualify for PIRP Protective Measures must also be qualified as a Participating Intermittent Resource for the term over which they are to receive the PIRP Protective Measures.

4.8.3.2.1 Exposure to Real-Time Imbalance Energy

The Participating Intermittent Resource, or Qualifying Facility upon expiration of its Qualifying Facility contract with a Utility Distribution Company, either: (1) is subject to an existing bilateral agreement for power purchases from the affected resource, such as a power purchase agreement, that is in effect the day this Section becomes effective, and such agreement in its totality requires that the resource owner directly or indirectly is subject to Real-Time Imbalance Energy Settlement in the CAISO Market; or (2) is not subject to any bilateral agreement for power purchases from the affected resource on the day this section becomes effective and, therefore, the resource is itself subject to Real-Time Imbalance Energy Settlement in the CAISO Market.

4.8.3.2.2 Ability to Curtail

The affected resource must also meet one of the two criteria below:

4.8.3.2.2.1 Physical Limitation

More than fifty (50) percent of the Participating Intermittent Resource or Qualifying Facility is composed of technology that is unable to curtail output and cannot be made to do so without significant investment. Participating Intermittent Resources that only lack Dispatch, control, and telemetry or metering that require upgrades to be able to respond will not qualify. Participating

Intermittent Resources that require production facility investments, such as turbine replacements, will qualify.

4.8.3.2.2.2 Contractual Limitation

The resource is subject to an existing bilateral agreement for power purchases, such as a power purchase agreement, that is in effect on the date on which this Section become effective, and that prohibits the resource from curtailing its output (not including times when they are ordered to do so by the CAISO or an affected Utility Distribution Company for reliability reasons).

4.8.3.3 Term of PIRP Protective Measures

The PIRP Protective Measures for a specific Participating Intermittent Resource shall be in effect until the earlier date of (1) three years after the effective date of this Section, or (2) the execution between the Participating Intermittent Resource owner and its counterparty of a new or amended power purchase agreement (or similar contract for services) that addresses their Imbalance Energy settlement.

4.8.3.4 Posting

The CAISO will post on its Website the names of the Participating Intermittent Resources that have elected, and subsequently been qualified, to receive PIRP Protective Measures.

* * *

4.9.5.2 The Scheduling Coordinator for the MSS will designate, in discrete quantities and with prices for both Ancillary Services and Energy: (1) Bids in the Day-Ahead Market and Real-Time Market (including Bids for internal Generation and internal Demand within the MSS), (2) Submissions to Self-Provide Ancillary Services or Bids for Regulation, Spinning Reserve, and Non-Spinning Reserve, capacity and associated Bid for Energy, or (3) any feasible combination thereof.

* * *

6.5.4 RTM Communications Before The Trading Hour

The RTM is intended to open at 1:00 p.m. the day before the target Operating Day to coincide with the posting of results from the DAM, which may be delayed for reasons specified in Section

31.6. Scheduling Coordinators can submit Bids into the RTM as of the time such results are posted.

6.5.4.1 Communications With Scheduling Coordinators

6.5.4.1.1 Before one hundred thirty-five (135) minutes before the Trading Hour, the CAISO will continuously screen Inter-SC Trades of Energy for the RTM, Inter-SC Trades of Ancillary Services, and Inter-SC Trades of IFM Load Uplift Obligations submitted by Scheduling Coordinators and will communicate with the Scheduling Coordinators about the consistency and validity of these Inter-SC Trades based on information available to the CAISO.

6.5.4.1.2 Between one hundred thirty-five (135) minutes before the Trading Hour and forty-five (45) minutes before the Trading Hour, the CAISO will perform the pre-market validation check for Inter-SC Trades for the RTM and Inter-SC Trades of Ancillary Services and will provide feedback to the Scheduling Coordinators about the validity of these Inter-SC Trades based on information available to the CAISO.

*** * ***

6.5.4.1.5 No later than forty-five (45) minutes before the Trading Hour, on an hourly basis, the CAISO will publish via the secure communication system results of the HASP processes.

6.5.4.1.6 [Not Used]

*** * ***

6.5.4.2.1 By one hundred five (105) minutes before the Trading Hour the CAISO will publish information regarding Outages on the transmission system on OASIS that will be used for Congestion Management, HASP Block Intertie Schedules and HASP Advisory Schedules that involve an Intertie transaction.

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

(a) Total HASP Block Intertie Schedules and HASP Advisory Schedules that involve an Intertie transaction for imports and exports by TAC Area and for the entire CAISO Balancing Authority Area;

(b) HASP advisory LMPs by PNode and APNode;

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

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

6.5.5 Real-Time Market Communications During the Trading Hour

The CAISO shall issue Dispatch Instructions to Scheduling Coordinators determined pursuant to the RTM throughout any given day.

*** * ***

6.5.5.2.2 Every fifteen (15) minutes the CAISO shall post via OASIS information regarding the status of the RTM. This information shall include but is not limited to the following:

(a) Total Real-Time AS Awards by AS Region and AS type

(b) Real-Time ASMPs by AS Region and AS type; and

(c) FMM LMP.

* * *

7.6.1 Actions For Maintaining Reliability Of CAISO Controlled Grid

The CAISO shall obtain the control over Generating Units that it needs to control the CAISO Controlled Grid and maintain reliability by ensuring that sufficient Energy and Ancillary Services are procured through the CAISO Markets. When the CAISO responds to events or circumstances, it shall first use the generation control it is able to obtain from the Energy and Ancillary Services Bids it has received to respond to the operating event and maintain reliability. Only when the CAISO has used the Energy and Ancillary Services that are available to it under such Energy and Ancillary Services Bids which prove to be effective in responding to the problem and the CAISO is still in need of additional control over Generating Units, shall the CAISO assume supervisory control over other Generating Units. It is expected that at this point, the operational circumstances will be so severe that a Real-Time system problem or emergency condition could be in existence or imminent.

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

(a) compliance with Dispatch Instructions including instructions to deliver Energy and Ancillary Services in Real-Time pursuant to the AS Awards, Day-Ahead Schedules and FMM Schedules, and FMM AS Awards;

(b) compliance with the system operation requirements set out in this Section 7;

(c) notification to the CAISO of the persons to whom an instruction of the CAISO should be directed on a 24-hour basis, including their telephone and facsimile numbers; and

(d) the provision of communications, telemetry and direct control requirements, including the establishment of a direct communication link from the control room of the Generator to the CAISO in a manner that ensures that the CAISO will have the ability, consistent with this CAISO Tariff, to direct the operations of the Generator as necessary to maintain the reliability of the CAISO Controlled Grid, except that a Participating Generator will be exempt from CAISO requirements imposed in accordance with this subsection (d) with regard to any Generating Unit with a rated capacity of less than ten (10) MW, unless that Generating Unit is certified by the CAISO to provide Ancillary Services.

7.7 Management Of System Emergencies

7.7.1 System Emergency

When, in the judgment of the CAISO, the System Reliability of the CAISO Controlled Grid is in danger of instability, voltage collapse or under-frequency caused by transmission or Generation trouble in the CAISO Balancing Authority Area, or events outside of the CAISO Balancing Authority Area that could result in a cascade of events throughout the WECC grid, the CAISO will declare a System Emergency. This declaration may include a notice to suspend the Day-Ahead

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

*** * ***

7.7.3.2 System Warning

The CAISO will give an AWE Notice of a system warning when the operating requirements for the CAISO Controlled Grid are not being met in the Real-Time Market, or the quantity of Regulation, Spinning Reserve, Non-Spinning Reserve, and Energy available to the CAISO is not acceptable for the Applicable Reliability Criteria. This system warning notice will notify Market Participants that the CAISO will, acting in accordance with Good Utility Practice, take such steps as it considers necessary to ensure compliance with Applicable Reliability Criteria, including the negotiation of commitments for Generation through processes other than competitive Bids.

*** * ***

7.7.11.4.2 If the CAISO forecasts in advance of the RTM that Load curtailment will be necessary due to a resource deficiency as determined pursuant to Section 40.7, the CAISO will identify any UDC or MSS Service Area that is resource deficient. The CAISO will provide notice to all Scheduling Coordinators if one or more UDC or MSS is deficient. If Load curtailment is required to manage a System Emergency associated with a resource deficiency determined pursuant to Section 40.7, the CAISO will determine the amount and location of Load to be curtailed and will allocate a portion of that required Load curtailment to each UDC or MSS Operator whose Service Area has been identified as being resource-deficient based on the ratio of its resource deficiency to the total Balancing Authority Area resource deficiency. Each UDC or MSS Operator shall be

responsible for notifying its customers and Generators connected to its system of curtailments and service interruptions.

*** * ***

7.7.14.2.2 Communications during Unavailability of CAISO's Secure Communication System

During any period of CAISO's secure communication system unavailability, the CAISO shall:

(a) make all reasonable efforts to keep Market Participants aware of current CAISO Controlled Grid status using voice communications;

(b) use the most recent set of Day-Ahead Schedules, RUC Schedules, AS Awards, FMM Schedules, and Dispatch Instructions for each Scheduling Coordinator for the current and all future Settlement Periods and/or Trading Days until the CAISO's secure communication system is restored; and

(c) attempt to take critical Bids, including ETC and TOR Self-Schedules changes, from Scheduling Coordinators via voice communications as time and personnel availability allows.

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7.7.15.2.2 Consequences of Removal of a Bid

The CAISO may remove part of a Bid, but retain other parts of the Bid for the applicable CAISO Market run and interval for the same or different product, and may retain parts of the Bid for subsequent CAISO Market runs or intervals. If a particular Energy or Ancillary Service Bid must be removed pursuant to Section 7.7.15.2.1, the CAISO will remove the entire Bid for that particular service and market. The Scheduling Coordinator may resubmit removed Bids in subsequent CAISO Markets, provided the Scheduling Coordinator complies with any operator instructions regarding the subject Bids. In the event a Bid is removed from an IFM run, the RUC Availability Bid associated with the removed IFM Bid may still be accepted for the corresponding RUC run, unless the RUC Availability Bid is determined to be the cause of the disruption. A problematic Bid as described in Section 7.7.15.2.1 will typically be identified as infeasible prior to

publication of the CAISO Market interval in which it is causing a problem, in which case to the extent practicable the CAISO may remove the Bid, execute the CAISO Market without the removed Bid, and publish a CAISO Market result for that interval. In some instances, a Bid may be able to clear through the IFM without causing an infeasibility issue, but then it may be necessary to remove the RUC Availability Bid associated with the IFM Bid for the corresponding RUC run due to infeasibility issues raised for the RUC run. In the Real-Time Market, for reasons discussed above, the CAISO may also be required to remove a Bid for a Non-Dynamic System Resource that normally would be accepted in the HASP, yet may be able to utilize and accept the Bid for the RTD and non-HASP RTUC runs of the Real-Time Market included within the same Scheduling Coordinator Bid submission.

If, for the reasons discussed above, the CAISO is required to remove a Bid in the advisory RTUC or RTD runs conducted for future intervals during the Real-Time Market, the removed Bid may still be used in the binding runs of the Real-Time Market for the same interval if the problems previously experienced with the Bid do not arise. If an Ancillary Service Bid or Submission to Self-Provide Ancillary Services is removed from the IFM, the Scheduling Coordinator may resubmit these components in the RTM provided the issues identified in the IFM have been resolved and the Bid or submission is otherwise consistent with the Ancillary Service bidding rules in the CAISO Tariff. If the CAISO is required to remove an Ancillary Services Bid submitted to the Real-Time Market, the CAISO may retain the Energy Bid submitted in association with the Ancillary Services Bid for that CAISO Market run.

7.7.15.2.3 Settlement Consequences of Removal of Bids

In the event that a Bid is removed from the Day-Ahead Market, the Scheduling Coordinator whose Bid is removed will not be subject to Settlement for the Day-Ahead Market for the affected service. The Scheduling Coordinator may then resubmit the Bid in the Real-Time Market for the same service and, to the extent the Bid is feasible and the issues identified have been resolved, it may be accepted in the Real-Time Market consistent with the CAISO Tariff requirements that apply to the Real-Time Market. In the case of Ancillary Services Bids, including Submissions to Self-Provide an Ancillary Service, that are removed from the Day-Ahead Market, the Scheduling

Coordinator will not receive Settlement for the Ancillary Services in the Day-Ahead Market and will not receive an opportunity cost payment in the Day-Ahead Market for the offered service. If the Bid is accepted in the Real-Time Market, the Scheduling Coordinator will be subject to Settlement based on the CAISO Market in which the Bid actually clears. In the event that a Bid is removed from a CAISO Market run or interval, the CAISO may subsequently be required to issue an Exceptional Dispatch for the resource, in which case the Scheduling Coordinator will receive Exceptional Dispatch Settlement as provided in Section 11.5.6. In the event that a Demand Bid is removed from the Day-Ahead Market, because no Demand Bids for load can be submitted in the Real-Time Market, Scheduling Coordinators for the load not cleared in the Day-Ahead Market will be settled as Uninstructed Imbalance Energy as provided in Section 11.5.2.

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8. Ancillary Services

8.1 Scope

The CAISO shall be responsible for ensuring that there are sufficient Ancillary Services available to maintain the reliability of the CAISO Controlled Grid consistent with NERC and WECC reliability standards and any requirements of the NRC. The CAISO's Ancillary Services requirements may be self-provided by Scheduling Coordinators as further provided in the Business Practice Manuals. Those Ancillary Services which the CAISO requires to be available but which are not being self-provided will be competitively procured by the CAISO from Scheduling Coordinators in the Day-Ahead and Real-Time Markets consistent with Section 8.3. The provision of Ancillary Services from the Interties with interconnected Balancing Authority Areas is limited to Ancillary Services bid into the competitive procurement processes in the IFM and RTM. The CAISO will not accept Submissions to Self-Provide Ancillary Services that are imports to the CAISO Balancing Authority Area over the Interties with interconnected Balancing Authority Areas, except from Dynamic System Resources certified to provide Ancillary Services or if provided pursuant to ETCs, TORs or Converted Rights. The CAISO will accept Submissions to Self-Provide Ancillary Services from Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area if they are certified to provide Ancillary Services. The CAISO will calculate

payments for Ancillary Services supplied by Scheduling Coordinators and charge the cost of Ancillary Services to Scheduling Coordinators based on their Ancillary Service Obligations.
For purposes of this CAISO Tariff, Ancillary Services are: (i) Regulation Up and Regulation Down, (ii) Spinning Reserve, (iii) Non-Spinning Reserve, (iv) Voltage Support, and (v) Black Start capability.
These services will be procured as stated in Section 8.3.5. Bids for these services may be submitted by a Scheduling Coordinator for resources that are capable of providing the specific service and that meet applicable Ancillary Service standards and technical requirements, as set forth in Sections 8.1 through 8.4, and are certified by the CAISO to provide Ancillary Services. Identification of specific services in this CAISO Tariff shall not preclude development of additional interconnected operation services over time. The CAISO and Market Participants will seek to develop additional categories of these unbundled services over time as the operation of the CAISO Controlled Grid matures or as required by regulatory authorities.

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8.2.3.1 Regulation Service

The CAISO shall maintain sufficient resources immediately responsive to the CAISO's EMS control in order to provide sufficient Regulation service to allow the CAISO Balancing Authority Area to meet NERC and WECC reliability standards and any requirements of the NRC by continuously balancing resources to meet deviations between actual and scheduled Demand and to maintain Interchange Schedules. The quantity of Regulation Down and Regulation Up capacity needed for each Settlement Period of the Day-Ahead Market and in each fifteen (15) minute period in Real-Time shall be determined by the CAISO as a percentage of the applicable CAISO Forecast Of CAISO Demand for the Day-Ahead and Real-Time Markets. In HASP, the amount of advisory Regulation from Dynamic System Resources required for each Settlement Period in the next Trading Hour is also determined based on the CAISO Forecast Of CAISO Demand. The advisory awards of Regulation from Dynamic System Resources in HASP are not binding and are re-optimized through the FMM and RTD processes in the Real-Time Market. The

CAISO's determination is based upon its need to meet the NERC and WECC reliability standards and any requirements of the NRC.

The requirement for Regulation Down or Regulation Up needed for each Settlement Period of the Day-Ahead Market and in each fifteen (15) minute period in Real-Time shall each be accompanied by a requirement for Mileage as determined by the CAISO. The CAISO shall determine the Mileage requirements in any Settlement Period based on Regulation capacity requirements as well as the Bid-in Regulation capacity for that Settlement Period. Subject to operator adjustment, the Mileage requirement for either Regulation Up or Regulation Down will reflect the minimum of (a) the product of the respective Regulation capacity requirement and the System Mileage Multiplier; (b) the average Instructed Mileage for the applicable Trading Hour from the prior seven (7) days; or (c) the product of each resource's resource specific Mileage multiplier(s) and its Bid-in Regulation capacity summed for all resources.

The CAISO will publish on OASIS the estimated quantity, or the percentage used to determine the estimated quantity, of Regulation Reserves required for each hour of the Day-Ahead Market and in each fifteen (15) minute period in Real-Time for the Trading Day. The CAISO will publish on OASIS the Mileage requirements for each hour of the Day-Ahead Market and each fifteen (15) minute period in Real-Time for the Trading Day. The CAISO will also publish on OASIS the average Instructed Mileage from the prior seven (7) days for each hour of a Trading Day no later than seven (7) calendar days after the applicable Trading Day.

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8.3 Procurement; Certification And Testing; Contracting Period

8.3.1 Procurement Of Ancillary Services

The CAISO shall operate competitive Day-Ahead and Real-Time Markets to procure Ancillary Services. The Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) applications used in the Integrated Forward Market (IFM) and the Real-Time Market (RTM) shall calculate optimal resource commitment, Energy, and Ancillary Services Awards and Schedules at least cost to End-Use Customers consistent with maintaining System Reliability. Any Scheduling Coordinator representing resources, System Units,

Participating Loads, Proxy Demand Resources or imports of System Resources may submit Bids into the CAISO's Ancillary Services markets provided that it is in possession of a current certificate for the resources concerned. Regulation Up, Regulation Down, and Operating Reserves necessary to meet CAISO requirements not met by self-provision will be procured by the CAISO as described in this CAISO Tariff. The amount of Ancillary Services procured in the IFM is based on the CAISO Forecast Of CAISO Demand and the forecasted intertie schedules in the RTM for the Operating Hour net of (i) Self-Provided Ancillary Services from resources internal to the CAISO Balancing Authority Area (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area) and Dynamic System Resources certified to provide Ancillary Services and (ii) Ancillary Services self-provided pursuant to an ETC, TOR or Converted Right. The amount of additional Ancillary Services procured in the RTM is based on the CAISO Forecast Of CAISO Demand, the Day-Ahead Schedules established net interchange, and the forecast of the Intertie Schedules for the Operating Hour in the RTM net of (i) available awarded Day-Ahead Ancillary Services, (ii) Self-Provided Ancillary Services from resources internal to the CAISO Balancing Authority Area (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area) and Dynamic System Resources certified to provide Ancillary Services, and (iii) Ancillary Services self-provided pursuant to an ETC, TOR or Converted Right. The amount of Ancillary Services procured in the Real-Time Market is based upon the CAISO Forecast Of CAISO Demand and the net interchange for the Operating Hour from FMM Schedules net of (i) available awarded Day-Ahead Ancillary Services, (ii) Self-Provided Ancillary Services from resources internal to the CAISO Balancing Authority Area (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area) and Dynamic System Resources certified to provide Ancillary Services, (iii) additional Operating Reserves procured in the FMM, and (iv) Ancillary Services self-provided pursuant to an ETC, TOR or Converted Right. The CAISO may procure incremental Ancillary Services in the Real-Time Market based in part on a determination during the FMM that any Ancillary Services capacity awarded or self-provided in the Day-Ahead Market is not available as a result of a resource constraint or Transmission Constraints. Resource constraints may include but are not limited to an Outage of a resource or

Ramp Rate constraints. Incremental procurement in the Real-Time Market will exclude Ancillary Services Capacity the CAISO has determined is not available.

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

Awards of AS in the RTM to Non-Dynamic System Resources are for the entire next Operating Hour. The CAISO procurement of Ancillary Services from all other resources in the Real-Time Market is for a fifteen (15) minute FMM interval. The CAISO's procurement of Ancillary Services from Non-Dynamic System Resources, Dynamic System Resources and internal Generation (which includes Generation from Generating Units that are Pseudo-Ties to the CAISO Balancing Authority Area) in the Real-Time Market is based on the Ancillary Service Bids submitted or generated in the RTM consistent with the requirements in Section 30. The CAISO may also procure Ancillary Services pursuant to the requirements in Section 42.1 and as permitted under the terms and conditions of a Reliability Must-Run Contract.

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

8.3.2 Procurement from Internal And External Resources

The CAISO will procure Spinning Reserves and Non-Spinning Reserves from resources operating within the CAISO Balancing Authority Area (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area) and from imports of System Resources.

Scheduling Coordinators are allowed to bid Regulation from resources located outside the CAISO Balancing Authority Area by dynamically scheduling such System Resources certified to provide Regulation. Each System Resource used to bid Regulation must comply with the Dynamic Scheduling Protocol in Appendix M. Scheduling Coordinators may submit Bids for Operating Reserves from Non-Dynamic System Resources but they may not submit Bids for Regulation from such resources because these resources cannot be dynamically scheduled consistent with Appendix M. When bidding to supply Ancillary Services in the IFM or RTM, imports and Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area compete for use of Intertie transmission capacity when the requested use is in the same direction, e.g., imports of Ancillary Services and Ancillary Services from Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area compete with Energy on Interties in the import direction, and exports of Ancillary Services (i.e., on demand obligations) compete with Energy on Interties in the export direction. To the extent there is Congestion, imports of Ancillary Services and suppliers of Ancillary Services from Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area will pay Congestion costs in the IFM and RTM markets pursuant to Section 11.10.1.2.1.

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

The CAISO's use of an Ancillary Service Sub-Region occurs when the CAISO establishes a minimum or maximum limit for that Sub-Region. The CAISO's use of minimum and maximum procurement limits for Ancillary Services help to ensure that the Ancillary Services required in the CAISO Balancing Authority Area are dispersed appropriately throughout the CAISO Balancing Authority Area and accurately reflect the system topology and deliverability needs. The factors the CAISO will use in determining whether to establish or change minimum or maximum limits include, but are not limited to, the following: (a) the CAISO Forecast Of CAISO Demand, (b) the location of Demand within the Balancing Authority Area, (c) information regarding network and resource operating constraints that affect the deliverability of Ancillary Services into or out of an Ancillary Service Region, (d) the locational mix of generating resources, (e) generating resource Outages, (f) historical patterns of transmission and generating resource availability, (g) regional

transmission limitations and constraints, (h) transmission Outages, (i) Available Transfer Capability, (j) Day-Ahead Schedules or FMM Schedules involving Intertie transactions, (k) whether any Ancillary Services provided from System Resources requiring a NERC tag fail to have a NERC tag, and (l) other factors affecting System Reliability. Ancillary Services procured within a Sub-Region count toward satisfying the Ancillary Service requirements for the System Region or the Expanded System Region.

8.3.3.3 Notice to Market Participants

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

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8.3.5 Daily And Hourly Procurement

The CAISO shall procure Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve on a daily and Real-Time basis in the IFM and RTM, respectively. The CAISO shall procure Ancillary Services on a longer-term basis pursuant to Section 42.1.3 if necessary to meet Reliability Criteria. The CAISO shall contract for Voltage Support annually (or for such other period as the CAISO may determine is economically advantageous) and on a daily or hourly basis as required to maintain System Reliability. The CAISO shall contract annually (or for such other period as the CAISO may determine is economically advantageous) for Black Start Generation.

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8.3.7 AS Bidding Requirements

Scheduling Coordinators may submit Bids or Submissions to Self-Provide an Ancillary Service consistent with the rules specified in Section 30 and any further requirements in this Section 8.3.7. Scheduling Coordinators may (i) submit Bids or Submissions to Self-Provide an Ancillary Service from resources located within the CAISO Balancing Authority Area (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area) or Dynamic System Resources certified to provide Ancillary Services, (ii) submit Submissions to Self-Provide an Ancillary Service from System Resources located outside the CAISO Balancing Authority Area if provided pursuant to ETCs, TORs, or Converted Rights, (iii) submit Bids for Ancillary Services from Dynamic and Non-Dynamic System Resources located outside the CAISO Balancing Authority Area certified to provide Ancillary Services, or (iv) submit Inter-SC Trades of Ancillary Services. Ancillary Services procured in the IFM and in the Real-Time Market are comprised of the following: Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve. Each resource for which a Scheduling Coordinator wishes to submit Ancillary Service Bids must meet the requirements set forth in this CAISO Tariff. The same resource capacity may be simultaneously offered to the same CAISO Market for multiple Ancillary Services types. Ancillary Services Bids and Submissions to Self-Provide an Ancillary Service can be submitted up to seven (7) days in advance. The CAISO will only use Operating Reserve Ramp Rates for procuring capacity associated with the specific Ancillary Services. The CAISO will issue Real-Time Dispatch Instructions in the Real-Time Market for the Energy associated with the awarded capacity based upon the applicable Operational Ramp Rate submitted with the single Energy Bid Curve in accordance with Section 30.7.7. There is no ability to procure Ancillary Services for export.

To the extent a Scheduling Coordinator has an on-demand obligation to serve loads outside the CAISO Balancing Authority Area, it can do so provided that (1) it is using export transmission capacity available in Real-Time, and (2) the resource capacity providing Energy to satisfy the on-demand obligation is not under an RMR Contract or Resource Adequacy Capacity obligation, and has not been paid a RUC Availability Payment for the Trading Hour. All resources subject to the

Ancillary Services must offer requirements, as specified in Section 40.6, must submit Bids consistent with the requirements specified therein and in Section 30.

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8.4.1.2 Regulation Energy Management

THIS TARIFF SECTION WILL BECOME EFFECTIVE ON NOVEMBER 27, 2012.

The CAISO will make Regulation Energy Management available to Scheduling Coordinators for Non-Generator Resources located within the CAISO Balancing Authority Area that require Energy from the Real-Time Market to offer their full capacity as Regulation. A Scheduling Coordinator for a resource using Regulation Energy Management may submit a Regulation Bid for capacity (MW) of up to four (4) times the maximum Energy (MWh) the resource can generate or curtail for fifteen (15) minutes after issuance of a Dispatch Instruction. In the Real-Time Market, a Scheduling Coordinator for a resource using Regulation Energy Management will procure Imbalance Energy as needed to satisfy the sixty (60) minute continuous Energy requirement for Regulation Awards in the Day-Ahead Market.

Scheduling Coordinators may request to use Regulation Energy Management for these Non-Generator Resources by submitting a request to certify such a resource to provide Regulation using Regulation Energy Management. The owner or operator of a Resource using Regulation Energy Management must execute both a Participating Generator Agreement and/or Participating Load Agreement and may provide only Regulation in the CAISO Market. A resource using Regulation Energy Management may not provide Energy other than Energy associated with Regulation. Scheduling Coordinators for Resources using Regulation Energy Management may define a Ramp Rate for operating as Generation and a Ramp Rate for operating as Load, respectively. These resources shall comply with the requirements to provide Regulation as specified in this Section 8, Appendix K, and the CAISO's Operating Procedures, including the requirement to undergo a market simulation using Regulation Energy Management as part of the certification procedure.

Scheduling Coordinators for resources using Regulation Energy Management shall register these resources in the Master File. Scheduling Coordinators may only submit Bids for Regulation Up

and Regulation Down and Mileage for these resources. Scheduling Coordinators may not submit Energy Bids, Energy Self-Schedules, Residual Unit Commitment Bids, or Ancillary Service Bids other than Regulation and Mileage for these resources. Scheduling Coordinators may not submit any type of commitment costs as part of their Regulation Up and Regulation Down Bids for resources using Regulation Energy Management, including Start-Up Cost, Minimum Load Costs, Pumping Cost or Pump Shut-Down Costs, or Transition Cost. All other bidding rules for Regulation set forth in Section 30 shall apply to resources using Regulation Energy Management. The CAISO will settle Dispatches from resources using Regulation Energy Management as Instructed Imbalance Energy. The portion of Demand of Non-Generator Resources using Regulation Energy Management that is dispatched as Regulation in any Settlement Interval shall not be considered Measured Demand for purposes of allocating payments and charges pursuant to Section 11 during that Settlement Interval.

The CAISO shall control the resource's operating set point through its Energy Management System with the objective of maintaining the resource's operating set point at its preferred operating point. In the Day-Ahead Market and FMM, the procurement of Regulation from resources using Regulation Energy Management will not be constrained by the resource's MWh limit to generate, curtail the consumption of, or consume Energy continuously. In the Real-Time Dispatch, the CAISO will base the Dispatches on the resource's capability to provide Regulation. When the resource has a physical MWh limit, the CAISO will observe the resource's MWh constraint during Real-Time Dispatch and will assess whether the CAISO can support the resource's self-provided Regulation capacity or Regulation award with Real-Time Market Dispatches. To the extent the CAISO determines in the Integrated Forward Market or FMM that the MWh constraint of resources using Regulation Energy Management limits the capability of the CAISO, through Real-time Dispatch, to support these resources' self-provided Regulation capacity or Regulation awards, the CAISO may disqualify resources using Regulation Energy Management on a pro rata basis across the System Region from providing Regulation, which shall result in the rescission of the disqualified portion of the resources' self-provided or awarded Regulation capacity payments.

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8.6.1 Ancillary Service Obligations

Each Scheduling Coordinator shall be assigned a share of the total Regulation Down, Regulation Up, Spinning Reserve, and Non-Spinning Reserve requirements by the CAISO, as set forth in Sections 11.10.2, 11.10.3 and 11.10.4, (i.e., a share of the total requirements for each Ancillary Service in the Day-Ahead Market and the Real-Time Market).

8.6.2 Right To Self-Provide

Each Scheduling Coordinator may choose to self-provide all, or a portion, of its Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve obligations in the IFM, and, to the extent needed to satisfy the CAISO's additional requirement, the Real-Time Market, from resources eligible for self-provision, as may be permissible for any given Ancillary Service in these respective markets. The right to self-provide Ancillary Services from capacity that is under a contractual obligation to provide Energy, including but not limited to capacity subject to an RMR Contract and local Resource Adequacy Resources, shall be conditional; self-provision of Ancillary Services from such capacity will only be permitted to the extent that capacity is not needed for Energy as a result of the MPM process described in this CAISO Tariff. To self-provide Ancillary Services a Scheduling Coordinator must provide the CAISO with a Submission to Self-Provide an Ancillary Service. Both Ancillary Service Bids and Submissions to Self-Provide an Ancillary Service can be provided to the CAISO for the same Ancillary Service and for the same hour in the same market. To the extent the Submission to Self-Provide an Ancillary Service is from a resource that is a Partial Resource Adequacy Resource, and Energy is needed, including for purposes under Section 31.3.1.3, from that resource the CAISO shall only disqualify the self-provision of Ancillary Services from the portion of the resource's capacity that has must-offer obligation, provided that the Scheduling Coordinator has not submitted an Energy Bid for the capacity that is not subject to a must-offer obligation. The CAISO will treat resources subject to Resource Adequacy requirements consistently with and such resources must comply with the bidding requirements in Section 40.6. If there is an Energy Bid submitted for the capacity of a Partial Resource Adequacy Resource that is not subject to a must-offer obligation the CAISO

may disqualify the Submission to Self-Provide an Ancillary Service for the portion of the resources capacity that is not under a must-offer obligation consistent with the principles of co-optimization under the CAISO Tariff.

Prior to evaluating Ancillary Service Bids, the CAISO will determine whether Submissions to Self-Provide Ancillary Services are feasible with regard to resource operating characteristics and regional constraints and are qualified to provide the Ancillary Services in the markets for which they were submitted.

If the total Submissions to Self-Provide Ancillary Services exceed the maximum regional requirement for the relevant Ancillary Service in an Ancillary Service Region, the submissions that would otherwise be accepted by the CAISO as feasible and qualified will be awarded on a pro-rata basis among the suppliers offering to self-provide the Ancillary Service up to the amount of the Ancillary Services requirement. If a regional constraint imposes a limit on the total amount of Regulation Up, Spinning Reserve, and Non-Spinning Reserve, and the total self-provision of these Ancillary Services in that region exceeds that limit, Self-Provided AS are qualified pro rata from higher to lower quality service in three tiers: Regulation Up first, followed by Spinning Reserve, and then by Non-Spinning Reserve. Submissions to Self-Provide Ancillary Services in excess of the maximum regional requirement for the relevant Ancillary Service in an Ancillary Service Region will not be accepted and qualified by the CAISO as Self-Provided Ancillary Services.

The CAISO shall schedule Self-Provided Ancillary Services to the extent qualified in the IFM and the RTM and Dispatch Self-Provided Ancillary Services in the Real-Time. To the extent that a Scheduling Coordinator self-provides Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve, the CAISO shall correspondingly reduce the quantity of the Ancillary Services it procures from Bids submitted in the IFM and the Real-Time Market. To the extent a Scheduling Coordinator's Self-Provided Ancillary Service for a particular Ancillary Service is greater than the Scheduling Coordinator's obligation for that particular Ancillary Service in a Settlement Interval, the Scheduling Coordinator will receive the user rate for the Self-Provided

Ancillary Service for the amount of the Self-Provided Ancillary Service in excess of the Scheduling Coordinator's obligation.

Scheduling Coordinators may trade Ancillary Services so that any Scheduling Coordinator may reduce its Ancillary Services Obligation through purchase of Ancillary Services capacity from another Scheduling Coordinator, or self-provide in excess of its obligation to sell Ancillary Services to another Scheduling Coordinator.

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8.6.4.2 RTM

In the RTM, Scheduling Coordinators shall be required to submit information on Self-Provided Ancillary Services within the time frame stated in Section 30.1. Failure to submit the required adjusted information within the stated time frame shall lead to the self-provision being declared invalid by the CAISO.

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8.7 Ancillary Services Awards

The CAISO shall provide Scheduling Coordinators with Ancillary Services Awards for the Day-Ahead and Real-Time Markets consistent with the provisions of the CAISO Tariff. The CAISO shall post the Ancillary Service Awards and Ancillary Service Schedules for the applicable Day-Ahead Market no later than the publication of the Day-Ahead Schedule for the applicable Day-Ahead Market; no later than approximately forty-five (45) minutes prior to the Operating Hour of AS awarded as a result of a HASP Block Intertie Schedule; and no later than approximately twenty-two and a half (22.5) minutes prior to the next FMM Interval. Where long-term contracts are involved, the information may be treated as standing information for the duration of the contract.

Once the CAISO has given Scheduling Coordinators notice of the Day-Ahead and Real-Time Market Ancillary Service Awards and Ancillary Service Schedules, these awards and Schedules represent binding commitments made in the markets between the CAISO and the Scheduling Coordinators concerned, subject to any amendments issued as described above.

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8.10.8.7 Rescission of Payments for Resource and Transmission Constraints

If the CAISO determines that any Day-Ahead Market award for Ancillary Services capacity or Self-Provided Ancillary Services capacity is not available during the RTM as a result of a resource constraint, then payments for that capacity will be rescinded in accordance with Section 11.10 or, in the case of Self-Provided Ancillary Services capacity, that capacity will not be compensated at the user rate as described in Sections 11.10.2, 11.10.3 and 11.10.4.

If the CAISO determines that any Day-Ahead Market award for Ancillary Services capacity or Self-Provided Ancillary Services capacity is not available during the RTM as a result of a Transmission Constraint, then payments for that capacity will not be rescinded, except as provided in section 11.10.9.1 for System Resources or, in the case of Self-Provided Ancillary Services capacity, that capacity will continue to be compensated at the user rate as described in Sections 11.10.2, 11.10.3 and 11.10.4.

For purposes of applying this Section to Dynamic Resources or Pseudo-Tie resources, the CAISO shall treat a reduction in the Operating Transfer Capability at an Intertie between the Day-Ahead Market and RTM that is registered in SLIC or any successor outage management system as a Transmission Constraint. For all other constraints that cause the CAISO to determine that any Day-Ahead Market award for Ancillary Services capacity or Self-Provided Ancillary Services capacity from Dynamic Resource or Pseudo-Tie resources is not available, the ISO shall treat these constraints as resource constraints.

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9.3.6.4 Changes to Maintenance Outages

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

Participants and reflect the availability of transmission capacity in the Real-Time Market as promptly as practicable.

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9.3.6.11 Cancellation of Approved Maintenance Outage

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

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9.3.10.2

Each Participating TO shall report any change or potential change in equipment status of the Participating TO's transmission assets turned over to the control of the CAISO or in equipment that affects transmission assets turned over to the control of the CAISO immediately upon discovery to the CAISO (this will include line and station equipment, line protection, Remedial Action Schemes and communication problems, etc.). Each Participating TO shall also keep the CAISO immediately informed upon discovery as to any change or potential change in the Participating TO's transmission system that could affect the reliability of the CAISO Controlled Grid. This would include, but is not limited to, adverse weather conditions, fires, bomb threats, system failures, etc. To the extent possible, the CAISO shall reflect all transmission Outages in the Integrated Forward Market and Real-Time Market.

* * *

11.1 Settlement Principles

The CAISO shall calculate, account for and settle payments and charges with Business Associates in accordance with the following principles:

(a) The CAISO shall be responsible for calculating Settlement balances for any penalty or dispute in accordance with the CAISO Tariff, and any transmission Access Charge to UDCs or MSSs and Participating TOs;

(b) The CAISO shall create and maintain computer back-up systems, including off- site storage of all necessary computer hardware, software, records and data at an alternative location that, in the event of a Settlement system breakdown at the primary location of the day-to-day operations of the CAISO, could serve as an alternative location for day-to-day Settlement operations within a reasonable period of time;

(c) The CAISO shall retain all Settlement data records for a period which, at least, allows for the re-run of data as required by this CAISO Tariff and any adjustment rules of the Local Regulatory Authority governing the Scheduling Coordinators and their End-Use Customers and FERC;

(d) The CAISO shall calculate, account for and settle all charges and payments for Initial Settlement Statement T+3B based on CAISO estimates and for all other settlement statements based on the Settlement Quality Meter Data it has received, or, if Settlement Quality Meter Data is not available, based on the best available information or estimate it has received in accordance with the provisions in Section 10 and the applicable Business Practice Manuals; and

(e) Day-Ahead Schedules, RUC Awards and AS Awards shall be settled at the relevant LMP, RUC Price, and ASMPs, respectively. FMM Schedules shall be settled at the relevant FMM LMP at the relevant Scheduling Point. FMM AS Awards shall be settled at the relevant FMM ASMP. All Dispatch Instructions shall be deemed delivered and settled

at relevant Real-Time Market prices. Deviations from Dispatch Instructions shall be settled as Uninstructed Deviations.

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11.1.2 Settlement Charges And Payments

The CAISO shall settle charges and payments as specified in this Section 11.

* * *

11.2.4.4.1 Daily Clearing of the CRR Balancing Account – Full Funding of CRRs

At the end of each day, all CRR Payment shortfalls for all CRR Holders shall be paid in full and all CRR Charge shortfalls shall be fully charged through the CRR Balancing Account clearing process. The net of these CRR Charges and CRR Payment shortfalls shall be added to the CRR Balancing Account for the applicable day. Any surplus or shortfall revenue amounts in the CRR Balancing Account will be distributed to Scheduling Coordinators in an amount equal to (a) the CRR Balancing Account surplus or shortfall amounts, times (b) the ratio of each Scheduling Coordinator's Measured Demand (net of the Scheduling Coordinator's Measured Demand associated with valid and balanced ETC or TOR Self-Schedule quantities for which IFM Congestion Credits and/or RTM Congestion Credits were provided in the same relevant day) divided by (c) the total Measured Demand for all Scheduling Coordinators for the relevant day (net of the total Measured Demand associated with valid and balanced ETC or TOR Self-Schedule quantities for which IFM Congestion Credits and/or RTM Congestion Credits were provided in the same relevant day).

* * *

11.2.4.6 Adjustment of CRR Revenue Related to Virtual Awards

In accordance with this Section 11.2.4.6, the CAISO will adjust the revenue from the CRRs of a CRR Holder that is also a Convergence Bidding Entity whenever either of the following creates a significant impact on the value of the CRRs held by that entity: the CRR Holder/Convergence Bidding Entity submits Virtual Bids; or the CRR Holder/Convergence Bidding Entity reduces in the

RTM an import or export awarded in a Day-Ahead Schedule. As set forth in Section 11.32, the CAISO will also adjust the revenue from the CRRs of a CRR Holder (regardless of whether the CRR Holder is also a Convergence Bidding Entity) where the Scheduling Coordinator representing that CRR Holder reduces in the RTM an import or export awarded in a Day-Ahead Schedule.

(a) For purposes of this Section 11.2.4.6 and the definition of Flow Impact, any reduction by a Scheduling Coordinator submitting Schedules on behalf of an entity that is a CRR Holder to an import or export Schedule in the RTM will be treated as a Virtual Award. For each CRR Holder subject to this Section 11.2.4.6, for each hour, and for each Transmission Constraint binding in the IFM or FMM the CAISO will calculate the Flow Impact of the Virtual Awards awarded to the Scheduling Coordinator that represents the CRR Holder, excluding Virtual Awards at LAPs and generation Trading Hubs.

(b) The CAISO will determine the peak and off-peak hours of the day in which Congestion on the Transmission Constraint was significantly impacted by the Virtual Awards awarded to the Scheduling Coordinator that represents the CRR Holder. Congestion on the Transmission Constraint will be deemed to have been significantly impacted by the Virtual Awards awarded to the Scheduling Coordinator that represents the CRR Holder if the Flow Impact passes two criteria. First, the Flow Impact must be in the direction to increase the value of the CRR Holder's CRR portfolio. Second, the Flow Impact must exceed the threshold percentage of the flow limit for the Transmission Constraint. The threshold percentage is ten (10) percent of the flow limit for each Transmission Constraint.

(c) For each peak or off-peak hour that passes both criteria in Section 11.2.4.6(b), the CAISO will compare the Transmission Constraint's

impact on the Day-Ahead Market value of the CRR Holder's CRR portfolio with the Transmission Constraint's impact on the FMM value of the CRR Holder's CRR portfolio, as applicable.

(d) The CAISO will adjust the peak or off-peak period revenue from the CRR Holder's CRRs in the event that, over the peak or off-peak period of a day, the Transmission Constraint's contribution to the Day-Ahead Market value of the CRR Holder's CRR portfolio exceeds the Transmission Constraint's contribution to the FMM value of the CRR Holder's CRR portfolio, as applicable. The amount of the peak period adjustment will be the amount by which the Transmission Constraint's contribution to the Day-Ahead Market value of the CRR Holder's CRR portfolio exceeds the Transmission Constraint's contribution to the FMM value of the CRR Holder's CRR portfolio for the peak-period hours that passed both criteria in Section 11.2.4.6(b), as applicable. The amount of the off-peak period adjustment will be the amount by which the Transmission Constraint's contribution to the Day-Ahead Market value of the CRR Holder's CRR portfolio exceeds the Transmission Constraint's contribution to the FMM value of the CRR Holder's CRR portfolio for the off-peak period hours that passed both criteria in Section 11.2.4.6(b), as applicable.

All adjustments of CRR revenue calculated pursuant to this Section 11.2.4.6 will be added to the CRR Balancing Account.

11.3 Settlement of Virtual Awards

11.3.1 Virtual Supply Awards

The CAISO will pay each Scheduling Coordinator with Virtual Supply Awards at an Eligible PNode or Eligible Aggregated PNode an amount equal to the Day-Ahead LMP at the Eligible PNode or Eligible Aggregated PNode multiplied by the MWhs of Virtual Supply Awards. Virtual Supply Awards subject to price correction will be settled as specified in Section 11.21. The CAISO will charge each Scheduling Coordinator with Virtual Supply Awards at an Eligible PNode

or Eligible Aggregated PNode an amount equal to the simple average of the four FMM LMPs for the applicable Trading Hour at the Eligible PNode or Eligible Aggregated PNode multiplied by the MWhs of Virtual Supply Awards.

11.3.2 Virtual Demand Awards

The CAISO will charge each Scheduling Coordinator with Virtual Demand Awards at an Eligible PNode or Eligible Aggregated PNode an amount equal to the Day-Ahead Market LMP at the Eligible PNode or Eligible Aggregated PNode multiplied by the MWhs of Virtual Demand Awards. Virtual Demand Awards subject to price correction will be settled as specified in Section 11.21. The CAISO will pay each Scheduling Coordinator with Virtual Demand Awards at an Eligible PNode or Eligible Aggregated PNode an amount equal to the simple average of the four FMM LMPs for the applicable Trading Hour at the Eligible PNode or Eligible Aggregated PNode multiplied by the IFM MWhs of Virtual Demand Awards.

11.4 [Not Used]

11.4.1 [Not Used]

11.4.2 [Not Used]

11.5 Real-Time Market Settlements

The CAISO shall calculate and account for Imbalance Energy for each Dispatch Interval and settle Imbalance Energy in the Real-Time Market for each Settlement Interval for each resource within the CAISO Balancing Authority Area and all System Resources dispatched in Real-Time. There are two categories of Imbalance Energy: FMM Instructed Imbalance Energy and RTD Imbalance Energy. RTD Imbalance Energy consists of RTD IIE and UIE. FMM IIE includes all Energy associated with the FMM Schedule. FMM Instructed Imbalance Energy is settled pursuant to Section 11.5.1.1, including any Energy related with HASP Intertie Block Schedules cleared through the FMM. RTD IIE is settled pursuant to Section 11.5.1.2 and UIE is settled pursuant to Section 11.5.2. In addition, the CAISO shall settle UFE as part of the Real-Time Market Settlements. To the extent that the sum of the Settlements Amounts for FMM IIE, RTD IIE, and UIE does not equal zero, the CAISO will assess charges or make payments for the resulting differences to all Scheduling Coordinators based on a pro rata share of their Measured

Demand for the relevant Settlement Interval, as further described in Section 11.5.4.Imbalance Energy due to Exceptional Dispatches, as well as the allocation of related costs, including Excess Costs Payments is settled as described in Section 11.5.6. The CAISO shall reverse RTM Congestion Charges for valid and balanced ETC and TOR Self-Schedules as described in Section 11.5.7. The CAISO will settle Energy for emergency assistance as described in Section 11.5.8.

11.5.1 Imbalance Energy Settlements

11.5.1.1 FMM Instructed Imbalance Energy Settlements

For each Settlement Interval, FMM IIE consists of the following types of Energy: (1) FMM Optimal Energy; (2) FMM Minimum Load Energy; (3) FMM Exceptional Dispatch Energy; (4) FMM Derate Energy; and (5) FMM Pumping Energy. Payments and charges for FMM IIE attributable to each resource in each Settlement Interval shall be settled by debiting or crediting, as appropriate, the specific Scheduling Coordinator's FMM IIE Settlement Amount. The FMM IIE Settlement Amounts for FMM Optimal Energy, FMM Minimum Load Energy, FMM Derate Energy, and FMM Pumping Energy shall be calculated as the product of the sum of all of these types of Energy and the FMM LMP. For MSS Operators that have elected net Settlement, the FMM IIE Settlement Amounts for Energy dispatched through the FMM optimization shall be calculated as the product of the FMM MSS Price and the sum of the following types of Energy: FMM Minimum Load Energy from System Units dispatched in FMM, FMM Derate Energy, and FMM Pumping Energy. For MSS Operators that have elected gross Settlement, regardless of whether that entity has elected to follow its Load or to participate in RUC, the FMM IIE for such entities is settled similarly to non-MSS entities as provided in this Section 11.5.1. The remaining FMM IIE Settlement Amounts for Exceptional Dispatches are settled pursuant to Section 11.5.6.

11.5.1.2 RTD Instructed Imbalance Energy Settlements

For each Settlement Interval, RTD IIE consists of the following types of Energy: (1) RTD Optimal Energy; (2) Residual Imbalance Energy; (3) RTD Minimum Load Energy; (4) RTD Exceptional Dispatch Energy; (5) Regulation Energy; (6) Standard Ramping Energy; (7) Ramping Energy Deviation; (8) RTD Derate Energy; (9) MSS Load Following Energy; (10) RTD Pumping Energy;

and (11) Operational Adjustments. Payments and charges for RTD IIE attributable to each resource in each Settlement Interval shall be settled by debiting or crediting, as appropriate, the specific Scheduling Coordinator's RTD IIE Settlement Amount. The RTD IIE Settlement Amounts for the Standard Ramping Energy shall be zero. The RTD IIE Settlement Amounts for RTD Optimal Energy, RTD Minimum Load Energy, Regulation Energy, Ramping Energy Deviation, RTD Derate Energy, and RTD Pumping Energy shall be calculated as the product of the sum of all of these types of Energy and the RTD LMP. For MSS Operators that have elected net Settlement, the RTD IIE Settlement Amounts for Energy dispatched through the RTD optimization shall be calculated as the product of the RTD MSS Price and the sum of the following types of Energy: RTD Minimum Load Energy from System Units dispatched in Real-Time, Regulation Energy, Ramping Energy Deviation, RTD Derate Energy, MSS Load Following Energy, and RTD Pumping Energy. For MSS Operators that have elected gross Settlement, regardless of whether that entity has elected to follow its Load or to participate in RUC, the RTD IIE for such entities is settled similarly to non-MSS entities as provided in this Section 11.5.1. The remaining RTD IIE Settlement Amounts are determined as follows: (1) IIE Settlement Amounts for Residual Imbalance Energy are determined pursuant to Section 11.5.5.; and (2) RTD IIE Settlement Amounts for Exceptional Dispatches are settled pursuant to Section 11.5.6.**11.5.2**

Uninstructed Imbalance Energy

Scheduling Coordinators shall be paid or charged a UIE Settlement Amount for each LAP, PNode or Scheduling Point for which the CAISO calculates a UIE quantity for each Settlement Interval. UIE quantities are calculated for each resource that has a Day-Ahead Schedule, Dispatch Instruction, Real-Time Interchange Export Schedule or Metered Quantity. For MSS Operators electing gross Settlement, regardless of whether that entity has elected to follow its Load or to participate in RUC, the UIE for such entities is settled similarly to how UIE for non-MSS entities is settled as provided in this Section 11.5.2. The CAISO shall account for UIE every five minutes based on the resource's Dispatch Instruction. For all resources, including Generating Units, System Units of MSS Operators that have elected gross Settlement, Physical Scheduling Plants, System Resources and all Participating Load and Proxy Demand Resources, the UIE Settlement

Amount is calculated for each Settlement Interval as the product of its UIE MWh quantity and the applicable RTD LMP. . The UIE Settlement Amount for non-Participating Load and MSS Demand under gross Settlement is settled as described in Section 11.5.2.2. For MSS Operators that have elected net Settlement, the UIE Settlement Amount is calculated for each Settlement Interval as the product of its UIE quantity and its Real-Time Settlement Interval MSS Price.

* * *

11.5.2.2 Hourly Real-Time Demand Settlement

The Default LAP Hourly Real-Time Price will apply to CAISO Demand and MSS Demand under net Settlement of Imbalance Energy, except for CAISO Demand not settled at the Default LAP as provided in Section 30.5.3.2. For each Settlement Interval, the differences between the Day-Ahead Scheduled CAISO Demand and Metered Demand (MWh) is settled at the Default LAP Hourly Real-Time Price or the Custom LAP Hourly Real-Time Price, as appropriate. For each Default LAP, the CAISO calculates the applicable Default LAP Hourly Real-Time Price as the weighted average LMP of the four Default LAP FMM LMPs and the twelve (12) five-minute Default LAP RTD LMPs. The CAISO calculates the weighted average LMP for each Default LAP as the summation of the weighted average SMEC, the weighted average MCC, and the weighted average MCL for that Default LAP. The CAISO calculates the weighted average SMEC, MCC, and MCL for each applicable Trading Hour based on the four applicable Default LAP FMM SMECs, MCCs, and MCLs, respectively, and the twelve (12) applicable Default LAP RTD SMECs, MCCs, and MCLs, respectively. For each Custom LAP, the CAISO calculates the applicable Custom LAP Hourly Real-Time Price as the weighted average LMP of the four Custom LAP FMM LMPs and the twelve (12) five-minute Custom LAP RTD LMPs. The CAISO calculates the weighted average LMP for each Custom LAP as the summation of the weighted average SMEC, the weighted average MCC, and the weighted average MCL for that Custom LAP. The CAISO calculates the weighted average SMEC, MCC, and MCL for each applicable Trading Hour based on the four applicable Custom LAP FMM SMECs, MCCs, and MCLs, respectively, and the twelve (12) applicable Custom LAP RTD SMECs, MCCs, and MCLs, respectively. In calculating the weighted average SMEC, MCC, and MCL for each hour for either the Default LAPs or

Custom LAPs, the CAISO determines the weights based on the difference between Day-Ahead Schedules at the applicable LAP and the CAISO Forecast of CAISO Demand used in the FMM multiplied by the relevant FMM LMP at the applicable LAP plus the difference between the CAISO Forecast of CAISO Demand used in the FMM and the CAISO Forecast of CAISO Demand used in the RTD multiplied by the relevant RTD LMP at the applicable LAP divided by the sum of the difference between Day-Ahead Schedules at the applicable LAP and the CAISO Forecast of CAISO Demand used in the FMM plus the difference between the CAISO Forecast Of CAISO Demand used in the FMM and the CAISO Forecast Of CAISO Demand used in the RTD. Furthermore, the Default LAP Hourly Real-Time Prices and the Custom LAP Hourly Real-Time Prices will be bounded by the maximum positive LMP and the lowest negative LMP for the applicable Trading Hour from those relevant intervals at the relevant LAP. If the calculated price exceeds the upper boundary or is below the lower boundary, then the Default LAP Hourly Real-Time Price or the Custom LAP Hourly Real-Time Price, as appropriate, instead will be calculated based on a weighted average price with the weightings based on gross deviations (absolute value of each deviation).

The Default LAP Hourly Real-Time Prices and the Custom LAP Hourly Real-Time Prices are further determined by the requirements in Section 27.2.2.2.1 and 27.2.2.2.2, respectively.

11.5.2.3 Revenue Neutrality Resulting from Changes in LAP Load Distribution Factors

Any resulting revenue from changes in the LAP Load Distribution Factors between the Day-Ahead Market and the Real-Time Dispatch shall be allocated to metered CAISO Demand in the corresponding Default LAP.

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11.5.3 Unaccounted For Energy (UFE)

For each Settlement Interval, the CAISO will calculate UFE for each utility Service Area for which the IOU or Local Publicly Owned Electric Utility has requested separate UFE calculation and has met the requirements applicable to a CAISO Metered Entity. The UFE will be settled as

Imbalance Energy at the Default LAP Hourly Real-Time Price calculated for each utility Service Area for which UFE is calculated separately. UFE will be allocated to each Scheduling Coordinator based on the ratio of its metered CAISO Demand within the relevant utility Service Area for which UFE is calculated separately to total metered CAISO Demand within that utility Service Area. UFE charges will not be estimated or included on Initial Settlement Statement T+3B.

11.5.4 Imbalance Energy Pricing; Non-Zero Offset Amount Allocation

11.5.4.1 [Not Used]

11.5.4.2 Allocations of Non-Zero Amounts of the Sum of IIE, UIE, UFE, the Real-Time Ancillary Services Congestion Revenues and Real-Time Virtual Awards Settlements

The CAISO will first compute (1) the Real-Time Congestion Offset and allocate it to all Scheduling Coordinators, based on Measured Demand, excluding Demand associated with ETC or TOR Self-Schedules for which a RTM Congestion Credit was provided as specified in Section 11.5.7, and excluding Demand associated with ETC, Converted Right, or TOR Self-Schedules for which an IFM Congestion Credit was provided as specified in Section 11.2.1.5; and (2) the Real-Time Marginal Cost of Losses Offset and allocate it to all Scheduling Coordinators based on Measured Demand, excluding Demand associated with TOR Self-Schedules for which a RTM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules was provided as specified in Section 11.5.7.2, and excluding Demand associated with TOR Self-Schedules for which an IFM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules was provided as specified in Section 11.2.1.7. For Scheduling Coordinators for MSS operators that have elected to Load follow or net settlement, or both, the Real-Time Marginal Cost of Losses Offset will be allocated based on their MSS Aggregation Net Measured Demand excluding Demand associated with TOR Self-Schedules for which a RTM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules was provided as specified in Section 11.5.7.2, and excluding Demand associated with TOR Self-Schedules for which an IFM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules was provided as specified in Section 11.2.1.7. For Scheduling Coordinators for MSS Operators regardless of

whether the MSS Operator has elected gross or net Settlement, the CAISO will allocate the Real-Time Congestion Offset based on the MSS Aggregation Net Non-ETC/TOR Measured Demand. To the extent that the sum of the Settlement amounts for IIE, UIE, UFE, the Real-Time Ancillary Services Congestion revenues and Virtual Awards settlements in the Real-Time Market in accordance with Section 11.3, less Real-Time Congestion Offset, and less the Real-Time Marginal Cost of Losses Offset, does not equal zero, the CAISO will assess charges or make payments for the resulting differences to all Scheduling Coordinators, including Scheduling Coordinators for MSS Operators that are not Load following MSSs and have elected gross Settlement, based on a pro rata share of their Measured Demand for the relevant Settlement Interval. For Scheduling Coordinators for MSS Operators that have elected net Settlement, the CAISO will assess charges or make payments for the resulting non-zero differences of the sum of the Settlement amounts for IIE, UIE, and UFE, the Real-Time Ancillary Services Congestion Revenues and Virtual Awards settlements in the Real-Time Market in accordance with Section 11.3, less Real-Time Congestion Offset and less the Real-Time Marginal Cost of Losses Offset, based on their MSS Aggregation Net Measured Demand. For Scheduling Coordinators for MSS Operators that have elected Load following, the CAISO will not assess any charges or make payments for the resulting non-zero differences of the sum of the Settlement amounts for IIE, UIE, and UFE, the Real-Time Ancillary Services Congestion Revenues and Virtual Awards settlements in the Real-Time Market in accordance with Section 11.3, less Real-Time Congestion Offset and less the Real-Time Marginal Cost of Losses Offset.

11.5.5 Settlement Amount for Residual Imbalance Energy

For each Settlement Interval, Residual Imbalance Energy settlement amounts shall be the product of the MWh of Residual Imbalance Energy for that Settlement Interval and the Bid, as mitigated pursuant to Section 39.7 that led to the Residual Imbalance Energy from the relevant Dispatch Interval in which the resource was dispatched, subject to additional rules specified in this section below and in Section 11.17. The relevant Dispatch Interval and Bid that led to the Residual Imbalance Energy may occur prior or subsequent to the interval in which the relevant Residual Imbalance Energy occurs and can be contiguous, or not, with the applicable Trading

Hour in which the relevant Residual Imbalance Energy Settlement Interval occurs. For MSS Operators the Settlement for Residual Imbalance Energy is conducted in the same manner, regardless of any MSS elections (net/gross Settlement, Load following or opt-in/opt-out of RUC). When a Scheduling Coordinator increases the Minimum Load amount for a resource through SLIC, for the Settlement Interval(s) during which the affected resource is ramping up towards or ramping down from such a Minimum Load change, the Residual Imbalance Energy for the applicable Settlement Interval(s) will be re-classified as Derate Energy and will be paid at the applicable RTD Locational Marginal Price.

11.5.6 Settlement Amounts For IIE From Exceptional Dispatch

For each Settlement Interval, the IIE Settlement Amount from each type of Exceptional Dispatch described in Section 34.11 is calculated as the sum of the products of the relevant FMM IIE or RTD IIE quantity for the Settlement Interval and the relevant FMM or RTD Settlement price for each type of Exceptional Dispatch as further described in this Section 11.5.6. For MSS Operators the Settlement for FMM or RTD IIE from Exceptional Dispatches is conducted in the same manner, regardless of any MSS elections (net/gross Settlement, Load following or opt-in/opt-out of RUC). Except for the Settlement price, Exceptional Dispatches to perform Ancillary Services testing, to perform PMax testing, and to perform pre-commercial operation testing for Generating Units are otherwise settled in the same manner as provided in Section 11.5.6.1. Notwithstanding any other provisions of this Section 11.5.6, the Exceptional Dispatch Settlement price that is applicable in circumstances in which the CAISO applies Mitigation Measures to Exceptional Dispatch of resources pursuant to Section 39.10 shall be calculated as set forth in Section 11.5.6.7.

11.5.6.1 Settlement for FMM or RTD IIE from Exceptional Dispatches used for System Emergency Conditions, for a Market Interruption, to Mitigate Overgeneration Conditions or to Prevent or Relieve Imminent System Emergencies

The Exceptional Dispatch Settlement price for incremental FMM or RTD IIE that is delivered as a result of an Exceptional Dispatch for System Emergency conditions, for a Market Interruption, to mitigate Overgeneration conditions, or to prevent or relieve an imminent System Emergency,

including forced Start-Ups and Shut-Downs, is the higher of the (a) applicable FMM or RTD LMP, (b) the Energy Bid price, (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. Costs for incremental Energy for this type of Exceptional Dispatch are settled in two payments: (1) incremental Energy is first settled at the applicable FMM or RTD LMP and included in the total IIE Settlement Amount described in Section 11.5.1.1; and (2) the incremental Energy Bid Cost in excess of the applicable FMM or RTD LMP at the relevant Location is settled pursuant to Section 11.5.6.1.1. The Exceptional Dispatch Settlement price for decremental IIE that is delivered as a result of an Exceptional Dispatch Instruction for a Market Interruption, or to prevent or relieve a System Emergency, is the minimum of (a) the FMM or RTD LMP, (b) the Energy Bid price subject to Section 39.6.1.4, (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. All Energy costs for decremental IIE associated with this type of Exceptional Dispatch are included in the total IIE Settlement Amount described in Section 11.5.1.1.

11.5.6.1.1 Settlement of Excess Cost Payments for Exceptional Dispatches used for System Emergency Conditions, for a Market Interruption, and to Avoid an Imminent System Emergency

The Excess Cost Payment for incremental Exceptional Dispatches used for emergency conditions, for a Market Interruption, or to avoid an imminent System Emergency is calculated for each resource for each Settlement Interval as the cost difference between the Settlement amount calculated pursuant to Section 11.5.6.1 for the applicable Exceptional Dispatch at the FMM or RTD LMP and delivered Exceptional Dispatch quantity at one of the following three costs: (1) the resource's Energy Bid Cost, (2) the Default Energy Bid cost, or (3) the Energy cost at the negotiated price, as applicable for System Resources, for the relevant Exceptional Dispatch.

11.5.6.2 Settlement of IIE from Exceptional Dispatches Caused by Modeling Limitations

The Exceptional Dispatch Settlement price for IIE that is consumed or delivered as a result of an Exceptional Dispatch to mitigate or resolve Congestion as a result of a transmission-related modeling limitation in the FNM as described in Section 34.11.3 is the maximum of (a) the FMM or RTD LMP, (b) the Energy Bid price, (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. Costs for incremental Energy for this type of Exceptional Dispatch are settled in two payments: (1) incremental Energy is first settled at the FMM or RTD LMP and included in the total IIE Settlement Amount described in Section 11.5.1.1; and (2) the incremental Energy Bid costs in excess of the applicable LMP at the relevant Location are settled per Section 11.5.6.2.3. The Exceptional Dispatch Settlement price for decremental IIE for this type of Exceptional Dispatch is the minimum of (a) the FMM or RTD LMP, (b) the Energy Bid price, (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. Costs for decremental IIE associated with this type of Exceptional Dispatch are settled in two payments: (1) decremental Energy is first settled at the FMM or RTD LMP and included in the total IIE Settlement Amount described in Section 11.5.1.1; and (2) the decremental Energy Bid costs in excess of the applicable LMP at the relevant Location are settled per Section 11.5.6.2.3.

11.5.6.2.2 [NOT USED]

11.5.6.2.3 Settlement of Excess Cost Payments for Exceptional Dispatches used for Transmission-Related Modeling Limitations

The Excess Cost Payment for Exceptional Dispatches used for transmission-related modeling limitations as described in Section 34.11.3 is calculated for each resource for each Settlement Interval as the cost difference between the Settlement amount calculated pursuant to Section 11.5.6.2.1 or 11.5.6.2.2 for the applicable delivered Exceptional Dispatch quantity at the FMM or RTD LMP and one of the following three costs: (1) the resource's Energy Bid Cost, 2) the Default

Energy Bid cost, or 3) the Energy cost at the negotiated price, as applicable for System Resources, for the relevant Exceptional Dispatch.

11.5.6.2.4 Exceptional Dispatches for Non-Transmission-Related Modeling Limitations

The Exceptional Dispatch Settlement price for incremental IIE that is consumed or delivered as a result of an Exceptional Dispatch to mitigate or resolve Congestion that is not a result of a transmission-related modeling limitation in the FNM as described in Section 34.11.3 is the maximum of the (a) FMM or RTD LMP, (b) Energy Bid price, (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. All costs for incremental Energy for this type of Exceptional Dispatch will be included in the total IIE Settlement Amount described in Section 11.5.1.1. The Exceptional Dispatch Settlement price for decremental IIE for this type of Exceptional Dispatch is the minimum of the (a) FMM or RTD LMP, (b) Energy Bid Price, (c) Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) negotiated price as applicable to System Resources. All costs for decremental IIE associated with this type of Exceptional Dispatch are included in the total IIE Settlement Amount described in Section 11.5.1.1.

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11.5.6.4 Settlement of IIE from Exceptional Dispatches for Testing

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

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11.5.6.6 Settlement of IIE from Exceptional Dispatches for Real-Time ETC and TOR Self-Schedules

The Exceptional Dispatch Settlement price for IIE from Real-Time ETC and TOR Self-Schedules shall be the FMM or RTD LMP. The IIE Settlement Amount for this type of Exceptional Dispatch shall be calculated as the product of the sum of all of these types of Energy and the FMM or RTD LMP. All Energy costs for these types of Exceptional Dispatches will be included in the IIE Settlement Amount described in Section 11.5.1.1.

11.5.6.7 Settlement of Exceptional Dispatch Energy

11.5.6.7.1 Settlement of Exceptional Dispatch Energy from Exceptional Dispatches of Resources Eligible for Supplemental Revenues

Except as specified in Section 11.5.6.7.3, the Exceptional Dispatch Settlement price for the Exceptional Dispatch Energy delivered by a resource that satisfies all of the criteria set forth in Section 39.10.1 shall be the higher of (a) the resource's Energy Bid price or (b) the FMM or RTD LMP.

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11.5.6.7.3 Exception to the Other Provisions of Section 11.5.6.7

Notwithstanding any other provisions of this Section 11.5.6.7, if the Energy Bid price for a resource that satisfies all of the criteria set forth in Sections 39.10.1 or 39.10.2 is lower than the Default Energy Bid price for the resource, and the FMM or RTD LMP is lower than both the Energy Bid price for the resource and the Default Energy Bid price for the resource, the Exceptional Dispatch Settlement price for the Exceptional Dispatch Energy delivered by the resource shall be the Energy Bid price for the resource.

11.5.7 Congestion Credit And Marginal Cost Of Losses Credit

11.5.7.1 RTM Congestion Credit for ETCs and TORs

The CAISO shall not apply charges or payments to Scheduling Coordinators related to the MCC associated with all Points of Receipt and Points of Delivery pairs associated with valid and balanced ETC Self-Schedules or TOR Self-Schedules after the Day-Ahead Market. The balanced portion for each ETC or TOR contract for each Settlement Interval will be based on the difference between: (1) the minimum of (a) the total Demand, (b) the total ETC or TOR Supply Self-Schedule submitted in RTM, including changes after twenty (20) minutes before the

applicable Trading Hour if such change is permitted by the Existing Contract, or (c) the Existing Contract maximum capacity as specified in the TRTC Instructions; and (2) the valid and balanced portion of the Day-Ahead Schedule. In determining the balanced portions, the CAISO evaluates the amounts based on the following variables: (a) for exports and imports, the CAISO shall use the schedule quantity specified in the Interchange schedule used for check out between CAISO and other Balancing Authority Areas; (b) for CAISO Demand, the CAISO shall use the metered CAISO Demand associated with the applicable ETC or TOR; and (c) for all Generation the CAISO shall use the quantity specified in the Dispatch Instructions. For each Scheduling Coordinator, the CAISO shall determine for each Settlement Interval the applicable RTM Congestion Credit for Imbalance Energy, which can be positive or negative, as the sum of the product of the relevant MWh quantity and the weighted average MCC at each Point of Receipt and Point of Delivery associated with the valid and balanced portions of that Scheduling Coordinator's ETC or TOR Self-Schedules. The weights in the two markets will be based on the absolute values of the (a) deviation of the FMM Schedule or the CAISO Forecast Of CAISO Demand used in the FMM from Day-Ahead Schedules and (b) deviation of the RTD schedule or the CAISO Forecast Of CAISO Demand used in the RTD from Day-Ahead Schedules.

11.5.7.2 RTM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules

For all Points of Receipt and Points of Delivery pairs associated with a valid and balanced TOR Self-Schedule submitted to the RTM pursuant to an existing agreement between the TOR holder and either the CAISO or a Participating TO as specified in Section 17.3.3, the CAISO shall not impose any charge or make any payment to the Scheduling Coordinator related to the MCL associated with such TOR Self-Schedules and will instead impose any applicable charges for losses as specified in the existing agreement between the TOR holder and either the CAISO or a Participating TO applicable to the relevant TOR. In any case in which the TOR holder has an existing agreement regarding its TORs with either the CAISO or a Participating TO, the provisions of the agreement shall prevail over any conflicting provisions of this Section 11.5.7.2. Where the provisions of this Section 11.5.7.2 do not conflict with the provisions of the agreement, the provisions of this Section 11.5.7.2 shall apply to the subject TORs. The balanced portion of the

TOR Self-Schedule after the Day-Ahead Market is the same balanced quantity mentioned in this Section 11.5.7.2 for the TOR Self-Schedule. For each Scheduling Coordinator, the CAISO shall determine for each Settlement Interval the applicable RTM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules for Imbalance Energy, which can be positive or negative, as the sum of the product of the relevant MWh quantity and the weighted average MCL at each eligible Points of Receipt and Points of Delivery associated with the valid and balanced portions of that Scheduling Coordinator's TOR Self-Schedules. The weights in the two markets will be based on the absolute values of the: (a) deviation of the FMM Schedule or the CAISO Forecast Of CAISO Demand used in the FMM from Day-Ahead Schedules; and (b) deviation of the RTD schedule or the CAISO Forecast Of CAISO Demand used in the RTD from Day-Ahead Schedules. For losses that the CAISO shall charge pursuant to Section 17.3.3, the specific loss charge amount shall be the product of (a) the specific loss percentage as may be specified in an applicable agreement between the TOR holder and the CAISO or an existing agreement between the TOR holder and a Participating TO, (b) the weighted average SMEC price from the FMM and RTD markets with weights based on the absolute values of (1) deviation of FMM schedule or CAISO Forecast Of CAISO Demand used in the FMM from Day-Ahead Schedules and (2) deviation of RTD schedule or CAISO Forecast Of CAISO Demand used in the RTD from Day-Ahead Schedules, and (c) the balanced contract quantity mentioned in Section 11.5.7.1.

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11.5.8.1 Settlement for Energy Purchased by the CAISO for System Emergency Conditions, to Avoid Market Interruption, or to Prevent or Relieve Imminent System Emergencies, Other than Exceptional Dispatch Energy

The Settlement price for Energy that is delivered to the CAISO from a utility in another Balancing Authority Area as a result of a CAISO request pursuant to Section 42.1.5 or any other provision for assistance in System Emergency conditions, to avoid a Market Interruption, or to prevent or relieve an imminent System Emergency, other than Energy from an Exceptional Dispatch, shall be either (i) a negotiated price agreed upon by the CAISO and the seller or (ii) a price established

by the seller for such emergency assistance in advance, as may be applicable. In the event no Settlement price is established prior to the delivery of the emergency Energy, the default Settlement price shall be the simple average of the relevant FMM and RTD LMPs at the applicable Scheduling Point, plus all other charges applicable to imports to the CAISO Balancing Authority Area, as specified in the CAISO Tariff. If the default Settlement price is determined by the seller not to compensate the seller for the value of the emergency Energy delivered to the CAISO, then the seller shall have the opportunity to provide the CAISO with cost support information demonstrating that a higher price is justified. The cost support information must be provided in writing to the CAISO within thirty (30) days following the date of the provision of emergency assistance. The CAISO shall have the discretion to pay that higher price based on the seller's justification of this higher price. The CAISO will provide notice of its determination whether to pay such a higher price within thirty (30) days after receipt of the cost support information. Any dispute regarding the CAISO's determination whether to pay a higher price for emergency assistance based on cost support information shall be subject to the CAISO ADR Procedures. Payment by the CAISO for such emergency assistance will be made in accordance with the Settlement process, billing cycle, and payment timeline set forth in the CAISO Tariff. The costs for such emergency assistance, including the payment of a price based on cost support information, will be settled in two payments: (1) the costs will first be settled at the simple average of the relevant Dispatch Interval LMPs and included in the total IIE Settlement Amount as described in Section 11.5.2.1; and (2) costs in excess of the simple average of the relevant Dispatch Interval LMPs plus other applicable charges will be settled in accordance with Section 11.5.8.1.1. The allocation of the amounts settled in accordance with Section 11.5.1.1 will be settled according to Section 11.5.4.2.

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11.8 Bid Cost Recovery

For purposes of determining the Unrecovered Bid Cost Uplift Payments for each Bid Cost Recovery Eligible Resource as determined in Section 11.8.5 and the allocation of Unrecovered Bid Cost Uplift Payments for each Settlement Interval, the CAISO shall sequentially calculate the

Bid Costs, which can be positive (IFM, RUC or RTM Bid Cost Shortfall) or negative (IFM, RUC or RTM Bid Cost Surplus) in the IFM, RUC and the Real-Time Market, as the algebraic difference between the respective IFM, RUC or RTM Bid Cost and the IFM, RUC or RTM Market Revenues as further described below in this Section 11.8. The RTM Energy Bid Costs and RTM Market Revenues include the FMM Energy Bid Costs. In any Settlement Interval a resource is eligible for Bid Cost Recovery payments pursuant to the rules described in the subsections of Section 11.8 and Section 11.17. Bid Cost Recovery Eligible Resources for different MSS Operators are supply resources listed in the applicable MSS Agreement. All Bid Costs shall be based on Bids as mitigated pursuant to the requirements specified in Section 39.7. Virtual Awards are not eligible for Bid Cost Recovery. Virtual Awards are eligible for make-whole payments due to price corrections pursuant to Section 11.21.2. In order to be eligible for Bid Cost Recovery, Non-Dynamic Resource-Specific System Resources must provide to the CAISO SCADA data by telemetry to the CAISO's EMS in accordance with Section 4.12.3 demonstrating that they have performed in accordance with their CAISO commitments. Scheduling Coordinators for Non-Generator Resources are not eligible to recover Start-Up Costs, Minimum Load Costs, Pumping Costs, Pump Shut-Down Costs, or Transition Costs but are eligible to recover Energy Bid Costs, RUC Availability Payments and Ancillary Service Bid Costs.

11.8.1 CAISO Determination Of Self-Commitment Periods

For the purposes of identifying the periods during which a Bid Cost Recovery Eligible Resource is deemed self-committed and thus ineligible for Start-Up Costs, Transition Costs, Minimum Load Costs, IFM Pump Shut-Down Costs and IFM Pumping Costs, the CAISO derives the Self-Commitment Periods as described below. The CAISO will determine the Self-Commitment Periods for Multi-Stage Generating Resources based on the applicable MSG Configuration. MSS resources designated for Load following are considered to be self-committed if they have been scheduled with non-zero Load following capacity, or are otherwise used to follow Load in the Real-Time. The IFM and RUC Self-Commitment Periods will be available as part of the Day-Ahead Market results provided to the applicable Scheduling Coordinator. The interim RTM Self-Commitment Periods as reflected in the RTM will be available as part of the RTM results for the

relevant Trading Hour as provided to the applicable Scheduling Coordinator. The final RTM Self-Commitment Period is determined ex-post for Settlements purposes. ELS Resources committed through the ELC Process described in Section 31.7 are considered to have been committed in the IFM Commitment Period for the applicable Trading Day for the purposes of determining BCR settlement in this section 11.8.

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11.8.1.3 Multi-Stage Generating Resource Start-Up, Minimum Load, or Transition Costs

For the settlement of the Multi-Stage Generating Resource Start-Up Cost, Minimum Load Cost, and Transition Cost in the IFM, RUC, and RTM, the CAISO will determine the applicable Commitment Period and select the applicable Start-Up Cost, Minimum Load Cost, and Transition Cost based on the following rules.

(1) In any given Settlement Interval, the CAISO will first apply the following rules to determine the applicable Start-Up Cost, Minimum Load Cost, and Transition Cost for the Multi-Stage Generating Resources. For a Commitment Period in which:

(a) the IFM Commitment Period and/or RUC Commitment Period MSG Configuration(s) are different from the RTM CAISO Commitment Period MSG Configuration, the Multi-Stage Generating Resource's Start-Up Cost, Minimum Load Cost, and Transition Cost will be settled based on the RTM CAISO Commitment Period MSG Configuration Start-Up Cost, and Transition Cost, as described in Section 11.8.4.1. This rule does not apply in cases where there is a CAISO IFM Commitment Period, in which case the Minimum Load Costs will be settled based on the: (i) CAISO IFM Commitment Period MSG Configuration's Minimum Load costs, plus (ii) the positive or negative difference of the CAISO RTM Commitment Period MSG

Configuration's Minimum Load Costs and the CAISO IFM Commitment Period MSG Configuration's Minimum Load Costs.

(b) there is a CAISO IFM Commitment Period and/or CAISO RUC Commitment Period in any MSG Configuration and there is also a RTM Self-Commitment Period in any MSG Configuration, the Multi-Stage Generating Resource's Start-Up Cost, Minimum Load Cost, and Transition Cost will be settled based on the CAISO IFM Commitment Period and/or CAISO RUC Commitment Period MSG Configuration(s) Start-Up Cost, Minimum Load Cost, and Transition Cost, as described in Sections 11.8.2.1 and 11.8.3.1, and further determined pursuant to part (2) of this Section below.

(c) the CAISO IFM Commitment Period and/or CAISO RUC Commitment Period MSG Configuration is the same as the CAISO RTM Commitment Period MSG Configuration, the Multi-Stage Generating Resource's Start-Up Cost, Minimum Load Cost, and Transition Cost will be settled based on the CAISO IFM Commitment Period and/or CAISO RUC Commitment Period MSG Configuration(s) Start-Up Cost, Minimum Load Cost, and Transition Cost described in Sections 11.8.2.1 and 11.8.3.1, and further determined pursuant to part (2) of this Section below.

(d) the IFM and RUC Self-Commitment Period MSG Configuration(s) are the same as the CAISO RTM Commitment Period MSG Configuration, then the Multi-Stage Generating Resource's Start-Up Cost, Minimum Load Cost, and Transition Cost will be settled based on the CAISO RTM Commitment

Period MSG Configuration Start-Up Cost, Minimum Load Cost, and Transition Cost as described in Section 11.8.4.1.

(2) In any given Settlement Interval, after the rules specified in part (1) above of this Section have been executed, the ISO will apply the following rules to determine whether the IFM or RUC Start-Up Cost, Minimum Load Cost, and Transition Cost apply for Multi-Stage Generating Resources. For a Commitment Period in which:

(a) the IFM Commitment Period MSG Configuration is different from the CAISO RUC Commitment Period MSG Configuration the Multi-Stage Generating Resource's Start-Up Cost, Minimum Load Cost, and Transition Cost will be settled based on the CAISO RUC Commitment Period MSG Configuration Start-Up Cost, Minimum Load Cost, and Transition Cost as described in Section 11.8.3.1.

(b) the CAISO IFM Commitment Period MSG Configuration is the same as the CAISO RUC Commitment Period MSG Configuration, the Multi-Stage Generating Resource's Start-Up Cost, Minimum Load Cost, and Transition Cost will be based on the CAISO IFM Commitment Period MSG Configuration Start-Up Cost, Minimum Load Cost, and Transition Cost as described in Section 11.8.2.1.

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11.8.2.2.1 CAISO IFM Commitment

For any Settlement Interval in a CAISO IFM Commitment Period the IFM Market Revenue for a Bid Cost Recovery Eligible Resource is the algebraic sum of the two products specified below. In the case of a Multi-Stage Generating Resource, the CAISO will calculate the market revenue at the Generating Unit or Dynamic Resource-Specific System Resource level.

(1) The product of the delivered MWh in the relevant Day-Ahead Schedule in that Trading Hour (where for Pumped-Storage Hydro Units and Participating Load operating in the pumping mode or serving Load the MWh is negative), and the relevant IFM LMP, divided by the number of Settlement Intervals in a Trading Hour.

(2) The product of the IFM AS Award from each accepted IFM AS Bid and the relevant Resource-Specific ASMP, divided by the number of Settlement Intervals in a Trading Hour.

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11.8.4 RTM Bid Cost Recovery Amount

For purposes of determining the RTM Unrecovered Bid Cost Uplift Payments as determined in Section 11.8.5, and for the purposes of allocation of Net RTM Bid Cost Uplift as described in Section 11.8.6.6 the CAISO shall calculate the RTM Bid Cost Shortfall or the RTM Bid Cost Surplus as the algebraic difference between the RTM Bid Cost and the RTM Market Revenues for each Settlement Interval. The RTM Bid Costs shall be calculated pursuant to Section 11.8.4.1. The RTM Market Revenues shall be calculated pursuant to Section 11.8.4.2. The Energy subject to RTM Bid Cost Recovery is the Instructed Imbalance Energy described in Section 11.5.1, excluding Standard Ramping Energy, Residual Imbalance Energy, Exceptional Dispatch Energy, Derate Energy, Ramping Energy Deviation, Regulation Energy and MSS Load Following Energy regardless of whether the Energy is from the FMM or RTD, and is subject to the application of the Real-Time Performance Metric as described in Section 11.8.4.4 and the Persistent Deviation Metric described in Section 11.17.

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11.8.4.1.4 RTM Pumping Bid Cost

For Pumped-Storage Hydro Units and Participating Load only, the RTM Pumping Bid Cost for the applicable Settlement Interval shall be the Pumping Cost submitted to the CAISO in the RTM divided by the number of Settlement Intervals in a Trading Hour. The Pumping Cost is negative since it represents the amount the entity is willing to pay to pump or serve Load. The

Pumping Cost is included in RTM Bid Cost computation for a Pumped-Storage Hydro Unit and Participating Load committed by the Real-Time Market to pump or serve Load, if it actually operates in pumping mode or serves Load in that Settlement Interval. The RTM Energy Bid Cost for a Participating Load for any Settlement Interval is set to zero for any Energy consumed in excess of instructed Energy. The RTM Pumping Bid Cost for any Settlement Interval is zero if: (1) the Settlement Interval is included in a RTM Self-Commitment Period for the Bid Cost Recovery Eligible Resource; (2) the Bid Cost Recovery Eligible Resource has been manually dispatched under an RMR Contract or the resource has been flagged as an RMR Dispatch in the Day- Ahead Schedule or the Real-Time Market in that Settlement Interval; (3) the Bid Cost Recovery Eligible Resource is not actually in pumping mode in that Settlement Interval; (4) that Settlement Interval is included in an IFM or RUC Commitment Period; or (5) the Bid Cost Recovery Eligible Resource is committed pursuant to Section 34.11.2 for the purpose of performing Ancillary Services testing or pre-commercial operation testing.

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11.8.4.2.1 For each Settlement Interval in a CAISO Real-Time Market Commitment Period, the RTM Market Revenue for a Bid Cost Recovery Eligible Resource is the algebraic sum of the elements listed below in this Section. For Multi-Stage Generating Resources the RTM Market Revenue calculations will be made at the Generating Unit or Dynamic Resource-Specific System Resource level.

(a) The sum of the products of the FMM or RTD Instructed Imbalance Energy (including Energy from Minimum Load of the Bid Cost Recovery Eligible Resource committed in RUC and where for Pumped-Storage Hydro Units and Participating Load operating in the pumping mode or serving Load, the MWh is negative), except Standard Ramping Energy, Residual Imbalance Energy, Exceptional Dispatch Energy, Derate Energy, MSS Load following Energy, Ramping Energy Deviation and Regulation Energy, with the relevant FMM and RTD LMP, for each Dispatch Interval in the Settlement Interval.

(b) The product of the Real-Time Market AS Award from each accepted Real-Time Market AS Bid in the Settlement Interval with the relevant ASMP, divided by the number of fifteen (15)-minute Commitment Intervals in a Trading Hour (4), and prorated to the duration of the Settlement Interval.

(c) The relevant tier-1 No Pay charges for that Bid Cost Recovery Eligible Resource in that Settlement Interval.

11.8.4.2.2 For each Settlement Interval in a non-CAISO Real-Time Market Commitment Period, the Real-Time Market Revenue for a Bid Cost Recovery Eligible Resource is subject to the Real-Time Performance Metric and is the algebraic sum of the following:

(a) The sum of the products of the FMM or RTD Instructed Imbalance Energy (excluding the Energy from Minimum Load of Bid Cost Recovery Eligible Resources committed in RUC), except, Standard Ramping Energy, Residual Imbalance Energy, Exceptional Dispatch Energy, Derate Energy, MSS Load Following Energy, Ramping Energy Deviation and Regulating Energy, with the relevant FMM or RTD Market LMP, for each Dispatch Interval in the Settlement Interval;

(b) The product of the Real-Time Market AS Award from each accepted Real-Time Market AS Bid in the Settlement Interval with the relevant ASMP, divided by the number of fifteen (15)-minute Commitment Intervals in a Trading Hour (4), and prorated to the duration of the Settlement Interval.

(c) The relevant tier-1 No Pay charges for that Bid Cost Recovery Eligible Resource in that Settlement Interval.

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11.8.6.6 Allocation of Net RTM Bid Cost Uplift

The hourly Net RTM Bid Cost Uplift is computed for the Trading Hour as the product of the uplift ratio in Section 11.8.6.3 and the sum over all of the Settlement Intervals of the Trading Hour of any positive Net RTM Bid Cost Uplift after the sequential netting in Section 11.8.6.2. The hourly

RTM Bid Cost Uplift is allocated to Scheduling Coordinators, including Scheduling Coordinators for MSS Operators that have elected (a) not to follow their Load, and (b) gross Settlement, in proportion to their Measured Demand plus any FMM reductions not associated with valid and balanced ETCs, TORs or Converted Rights Self-Schedules in the Day-Ahead Market for the Trading Hour. For Scheduling Coordinators for MSS Operators that have elected (a) not to follow their Load, and (b) net Settlement, the hourly RTM Bid Cost Uplift is allocated in proportion to their MSS Aggregation Net Measured Demand plus any FMM reductions not associated with valid and balanced ETCs, TORs or Converted Rights Self-Schedules in the Day-Ahead Market. For Scheduling Coordinators of MSS Operators that have elected to follow their Load, the RTM Bid Cost Uplift shall be allocated in proportion to their MSS Net Negative Uninstructed Deviation plus any FMM reductions not associated with valid and balanced ETCs, TORs or Converted Rights Self-Schedules in the Day-Ahead Market. Accordingly, each Scheduling Coordinator shall be charged an amount equal to its Measured Demand plus any FMM reductions not associated with valid and balanced ETCs, TORs or Converted Rights Self-Schedules in the Day-Ahead Market times the RTM Bid Cost Uplift rate, where the RTM Bid Cost Uplift rate is computed as the Net RTM Bid Cost Uplift amount divided by the sum of Measured Demand plus any FMM reductions not associated with valid and balanced ETCs, TORs or Converted Rights Self-Schedules in the Day-Ahead Market across all Scheduling Coordinators for the Trading Hour. Any real-time reductions after HASP results are published to HASP Block Intertie Schedules in response to Dispatch Instructions or real-time scheduling curtailments are not allocated any Net RTM Bid Cost Uplift.

11.9 Inter-SC Trades

11.9.1 Physical Trades

Inter-SC Trades of Energy in the Day-Ahead Market will be settled separately from Inter-SC Trades of Energy in the RTM. Both the Day-Ahead and RTM Inter-SC Trades of Energy will be settled on an hourly basis and the two respective Settlement amounts between the two parties for each market shall net to zero. All MWh quantities of Physical Trades submitted to the CAISO for Settlement in the Day-Ahead Market that are confirmed through the Physical Trade post market

confirmation as provided in Section 28.1.6.3 shall be settled at the Day-Ahead LMP at the relevant PNode. All MWh quantities of Physical Trades that are reduced during the Physical Trade post market confirmation shall be settled at the relevant Existing Zone (EZ) Generation Trading Hub price. All MWh quantities of Physical Trades submitted to the CAISO for Settlement in the RTM that are confirmed through the Physical Trade post market confirmation pursuant to Section 28.6.1.3 shall be settled at the simple average of the four FMM LMPs at the relevant Pricing Node. All MWh quantities of Physical Trades submitted for Settlement in RTM that are reduced during the Physical Trade post market confirmation shall be settled at the FMM price for the EZ Generation Trading Hub.

11.9.2 Inter-SC Trades At Aggregated Pricing Nodes

Inter-SC Trades of Energy at Aggregated Pricing Nodes in the Day-Ahead Market will be settled separately from Inter-SC Trades at Aggregated Pricing Nodes in the RTM. Both the Day-Ahead and RTM Inter-SC Trades at Aggregated Pricing Nodes will be settled on an hourly basis and the two respective Settlement amounts between the two parties for each market shall net to zero. All MWh quantities of Inter-SC Trades at Aggregated Pricing Nodes submitted to the CAISO for Settlement in the Day-Ahead Market shall be settled at the relevant Day-Ahead Aggregated Pricing Node price such as the Existing Zone (EZ) Generation Trading Hub price or LAP price. All MWh quantities of Inter-SC Trades at Aggregated Pricing Nodes submitted to the CAISO for Settlement in the RTM shall be settled at the relevant Real-Time Aggregated Pricing Node price.

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11.10.1.2 Ancillary Services Provided in HASP

The HASP optimization establishes Ancillary Services Awards and prices for Ancillary Services provided from HASP Block Intertie Schedules. The CAISO pays Scheduling Coordinators that supply Ancillary Services from HASP Block Intertie Schedules an amount equal to the product of the simple average of the ASMPs computed for the four FMM intervals for each Ancillary Service as described in Section 27.1.2, and the quantity of the capacity awarded for the Ancillary Service in the Settlement Period. The CAISO charges Scheduling Coordinators that

receive an Ancillary Service Award or have qualified Self-Provided Ancillary Services at a Scheduling Point in the FMM the simple average of the fifteen (15) minute Marginal Cost of Congestion over the applicable Trading Hour as described in Section 11.10.1.2.1.

11.10.1.2.1 Congestion Charges

If a Scheduling Coordinator, including a Scheduling Coordinator for a Pseudo-Tie of a Generating Unit to the CAISO Balancing Authority Area, receives an Ancillary Services Award or provides a qualified Self- Provided Ancillary Service at a congested Scheduling Point, the CAISO will charge the Scheduling Coordinator for Congestion. The charge for Congestion at such locations is equal to the simple average of the fifteen (15) minute applicable intertie constraint Shadow Price over the applicable Trading Hour at the location of the Ancillary Service Award, multiplied by the quantity of Ancillary Services Award or the capacity of the qualified Self-Provided Ancillary Service for the Settlement Period. No such charge for Congestion will apply when the Scheduling Coordinator provides Ancillary Services from HASP Block Intertie Schedules at Scheduling Points pursuant to the CAISO Tariff rules that apply to Existing Rights and Transmission Ownership Rights.

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11.10.1.3 Ancillary Services Provided in the FMM

Suppliers of Ancillary Services from resources awarded in FMM are paid a price equal to one-quarter of the fifteen (15) minute ASMP (in $/MW/h) in each fifteen (15) minute interval of the applicable Trading Hour in which the capacity is procured for each Ancillary Service times the amount of the capacity awarded (MW) for the Ancillary Service in the relevant Ancillary Services Region for the applicable trading hour in which the capacity is procured. For each Ancillary Service, the ASMP is calculated as set forth in Section 27.1.2. Suppliers of Self-Provided Ancillary Services in the Real-Time Market are not eligible to receive payment using the ASMP; rather to the extent the self-provision is qualified it will be valued at the user rate for the relevant service (i.e., will either reduce the Ancillary Services Obligation or receive the user rate if it exceeds the Scheduling Coordinator's Ancillary Service Obligation) as described in Sections 11.10.2, 11.10.3 and 11.10.4.

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11.10.2 Settlement For User Charges For Ancillary Services

The CAISO shall determine a separate hourly user rate for Regulation Down Reserve, Regulation Up Reserve, Spinning Reserve, and Non-Spinning Reserve purchased for each Settlement Period. The hourly user rates for Regulation Down, Regulation Up, Spinning Reserve, and Non-Spinning Reserve include the cost incurred by the CAISO across the Day-Ahead Market and the Real-Time Market to procure this service. In computing the user rate for each service the quantity (MW) and costs of any substituting Ancillary Service will be treated as if they are costs and MW associated with the Ancillary Service need they are being used to fulfill. Each rate will be charged to Scheduling Coordinators on a volumetric basis applied to each Scheduling Coordinator's obligation for the specific Ancillary Service concerned which it has not self-provided, as adjusted by any Inter-SC Trades of Ancillary Services.

Each Scheduling Coordinator's obligation for Regulation Down Reserve, Regulation Up Reserve, Spinning Reserve, and Non-Spinning Reserve shall be calculated in accordance with this Section 11.10.2, notwithstanding any adjustment to the quantities of each Ancillary Service purchased by the CAISO in accordance with Section 8.2.3.5. The cost of Voltage Support and Black Start shall be allocated to Scheduling Coordinators as described in Sections 11.10.7 and 11.10.8.

Ancillary Services Obligations for an individual Scheduling Coordinator (before taking into account Self-Provided Ancillary Services) or Inter-SC Trades of Ancillary Services may be negative. Credits for such negative obligations will be in accordance with the rates calculated in this Section 11.10.2, except that a Scheduling Coordinator's credit shall be reduced pro rata to the extent the sum of the negative obligations of all Scheduling Coordinators with the negative Ancillary Services Obligation (before self-provision or Inter-SC Trade) exceeds the obligation of all Scheduling Coordinators with positive obligation net of Self- Provided Ancillary Services, as specified in Section 11.10.5 in any Settlement Period, the net procurement quantity of Regulation Up, Regulation Down, Spinning Reserve, or Non-Spinning Reserve purchased by the CAISO in the Day-Ahead Market

and the Real-Time Market due to the operation of Section 8.2.3.5 is zero (0), then the user rate for that Ancillary Service type will be zero (0). With respect to each Settlement Period, in addition to the user rates determined in accordance with this Section 11.10.2, each Scheduling Coordinator shall be charged an additional amount equal to its proportionate share, based on total purchases by Scheduling Coordinators of Regulation Down, Regulation Up, Spinning Reserve, and Non-Spinning Reserve of the amount, if any, by which (i) the total payments to Scheduling Coordinators pursuant to this Section 11.10.2 for the Day-Ahead Market and the Real-Time Market, exceed (ii) the total amounts charged to Scheduling Coordinators pursuant to this Section 11.10.2, for the Day-Ahead Market and the Real-Time Market. If total amounts charged to Scheduling Coordinators exceed the total payments to Scheduling Coordinators, each Scheduling Coordinator will be refunded its proportionate share, based on total purchases by Scheduling Coordinators of Regulation Down, Regulation Up, Spinning Reserve, and Non-Spinning Reserve.
With respect to each Settlement Period, in addition to Ancillary Service charges at the applicable user rates determined in accordance with this Section 11.10.2, each Scheduling Coordinator shall be charged additional neutrality adjustment amounts for each Ancillary Service type pursuant to Sections 11.10.2.4, 11.10.2.2.3, 11.10.3.3, and 11.10.4.3 and a neutrality adjustment amount for upward Ancillary Service types pursuant to Section 11.14.

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11.10.4.1 Hourly User Rate Non-Spinning Reserves

The hourly user rate for Non-Spinning Reserves is calculated as the ratio of: i) the sum of the portion of the Non-Spinning Reserve Cost used to meet the Non-Spinning requirement and a portion of the Regulation Up and Spinning Reserve costs that can substitute for Non-Spinning Reserve and ii) the Net Procurement quantity of Non-Spinning Reserves by the CAISO ($/MW). The CAISO's Non-Spinning Reserve Cost includes the costs associated with any Regulation Up Reserve or Spinning Reserve capacity used as Non-Spinning Reserve under Section 8.2.3.5.

The CAISO's Non-Spinning Reserve Cost is equal to: (i) the revenues paid to the suppliers of the total awarded Non-Spinning Reserve capacity in the Day-Ahead Market and Real-Time Market, minus, (ii) the payments rescinded due to either the failure to conform to CAISO Dispatch Instructions or the unavailability of the Non-Spinning Reserves under Section 8.10.8. The Net Procurement of Non-Spinning Reserves is equal to: (i) the amount (MWs) of total awarded Non-Spinning Reserve capacity in the Day- Ahead Market and Real-Time Market, minus, (ii) the Non-Spinning Reserve capacity associated with payments rescinded pursuant to any of the provisions of Section 8.10.8. The amount (MW) of awarded Non-Spinning Reserve capacity includes the amounts (MW) associated with any Regulation Up Reserve or Spinning Reserve capacity used as Non-Spinning Reserve under Section 8.2.3.5.

*** * ***

11.10.9 Settlements Of Rescission Of Payments For AS Capacity

The rescission of payments for Ancillary Services for Undispatchable, Unavailable, and Undelivered Capacity applies to Ancillary Services that are awarded in the Day-Ahead Market or Real-Time Market and the rescission will be the weighted average of the Ancillary Service Marginal Prices (ASMPs) and Ancillary Services Award amounts for a resource across the Day-Ahead Market and Real- Time Market. For Self-Provided Ancillary Service capacity that becomes Undispatchable Capacity, Unavailable Capacity, or Undelivered Capacity, the rescission of Ancillary Services self-provision in the Day-Ahead Market and Real-Time Market reduces the relevant Scheduling Coordinator's effective Ancillary Services self-provision in the Ancillary Services cost allocation, effectively resulting in a charge back at the relevant Ancillary Services rate. The rescission of payments in this Section 11.10.9 shall not apply to a capacity payment for any particular Ancillary Service if the weighted average Ancillary Service Marginal Price (ASMP) is less than or equal to zero (0).

* * *

11.12.1 Settlement of Hourly PIRP Schedules – PIRP Protective Measures

The provisions in this Section 11.12.1 and its subsections will be in effect as of the day this Section becomes effective and the CAISO will implement these measures no later than twelve months after the effective date of this section.

11.12.1.1 Hourly Settlement

Scheduling Coordinators that represent Participating Intermittent Resources that have been qualified for PIRP Protective Measures pursuant to Section 4.8.3 will be subject to the following Settlement requirements. The CAISO will first settle the market outcomes for the Participating Intermittent Resources subject to PIRP Protective Measures consistent with the rules specified in Section 11.

11.12.1.2 PIRP Protective Measures Monthly Adjustments

At the end of the month, the CAISO will calculate the PIRP Protective Measures monthly resettlement, which it will base on the forecast established for the Participating Intermittent Resource 90 minutes prior to the applicable Trading Hour. For each month the CAISO will calculate the PIRP Protective Measures Settlement Amount as the total of: (1) the sum of the product of the 90 minute MWh amounts, for each hour of the month multiplied by the simple average of the RTD LMP for the applicable Trading Hour; and (2) the product of (a) the monthly netted MWh quantities under PIRP Protective Measures, which is the sum of the hourly differences between the ninety (90) minute MWh amounts and the Participating Intermittent Resource's 5-minute metered MWhs, and (b) the resource's monthly weighted average RTD LMP, where the weights are the metered Generation quantities associated with each RTD LMP. If the Scheduling Coordinator submits an Economic Bid or Self-Schedule to the Real-Time Market, the resource will be disqualified from PIRP Protective Measures for the remaining term that the PIRP Protective Measures are otherwise intended to apply. The disqualification will be in effect as of the Trading Day for which the Scheduling Coordinators submitted the Economic Bid. The CAISO will take the necessary steps to implement that disqualification and will make any necessary Settlement adjustments consistent with the change in status. In addition, for the intervals in which the Scheduling Coordinator submitted an Economic Bid for a the resource while

it was still qualified as a resource subject to PIRP Protective Measures, the resource will not be eligible for any Bid Cost Recovery related payments for such Economic Bids.

11.12.1.3 Use of Inter-Scheduling Coordinator Trades for Energy

To the extent a Participating Intermittent Resource that is subject to PIRP Protective Measures is contractually required to make use of the CAISO's Inter-Scheduling Coordinator Trade for Energy to effectuate payment transfers with its contractual counterparty, the Scheduling Coordinator may select a flag in its Master File to indicate its election to settle of any Physical or Converted Physical Inter-Scheduling Coordinator Trades for Energy submitted for the Participating Intermittent Resource at the Participating Intermittent Resource location as follows; the Inter-Scheduling Coordinator Trades will settle at the hourly simple average of the RTD LMP of the PNode at the affected PIR location. Financial Inter-Scheduling Coordinator Trades for Energy will not be eligible for such treatment.

11.12.2 Allocation Of Participating Intermittent Resources Protective Measures Costs/Revenues

For each month, the CAISO will calculate the difference between the charges and payments made to the Scheduling Coordinator for each Participating Intermittent Resource under its Settlement as specified in Sections 11, and the PIRP Protective Measurement resettlement amounts. The CAISO will charge or credit the differences to the Scheduling Coordinator and will allocate a corresponding credit or charge to all Scheduling Coordinators in proportion to each Scheduling Coordinator's aggregate Net Negative Uninstructed Deviations in that month relative to the aggregate Net Negative Uninstructed Deviations for all Scheduling Coordinators in the CAISO Balancing Authority Area in that month.

*** * ***

11.12.3.3 Participating Intermittent Resource Export Fee

A Participating Intermittent Resource Export Fee will be levied to Participating Intermittent Resources that have elected for PIRP Protective Measures in accordance with Section 5.3 of Appendix Q and Schedule 4 of Appendix F.

[Not Used] * * *

11.17.1.2.1 Rule 1

If six (6) or fewer Settlement Intervals out of the previous twenty-four (24) Settlement Intervals are flagged pursuant to the rules in Section 11.17.1.1, then: (a) the RTM Energy Bid Costs will be based on the applicable Energy Bid price as specified in Section 11.8.4.1.5, and (b) Residual Imbalance Energy will be settled based on the reference hour Energy Bid as specified in Section 11.5.5.

11.17.1.2.2 Rule 2

If seven (7) or more Settlement Intervals of the previous twenty-four (24) Settlement Intervals are flagged as exceeding the Persistent Deviation Metric Threshold, then for all the previous twenty-four(24) Settlement Intervals in the two-hour window: (a) the RTM Energy Bid Costs specified in Section 11.8.4.1.5 (i) for Optimal Energy above the Day-Ahead Scheduled Energy will be based on the lesser of the applicable Default Energy Bid price, the applicable Energy Bid price, as mitigated, or the applicable FMM or RTD Locational Marginal Price, and (ii) for Optimal Energy below the Day-Ahead Scheduled Energy the greater of the applicable Default Energy Bid price, the applicable Energy Bid price, as mitigated, or the applicable FMM or RTD Locational Marginal Price; and (b) Residual Imbalance Energy as specified in Section 11.5.5 (i) for Residual Imbalance Energy above the Day-Ahead Scheduled Energy will be based on the lesser of the applicable Default Energy Bid price, the relevant Energy Bid Price, as mitigated, or the applicable RTD Locational Marginal Price, and (ii) Residual Imbalance Energy below the Day-Ahead Scheduled Energy will be based on the greater of the applicable Default Energy Bid price, the relevant Energy Bid Price, or the applicable RTD Locational Marginal Price.

* * *

11.21.1 CAISO Demand and Exports

If the CAISO corrects an LMP in the upward direction pursuant to Section 35 that impacts Demand in the Day-Ahead Market and the FMM such that either a portion of or the entire cleared CAISO Demand or export Economic Bid curve becomes uneconomic, then the CAISO will calculate and apply the Price Correction Derived LMP for settlement of CAISO Demand and exports in Section 11.2.1.2, 11.2.3, 11.2.1.4 and 11.4.1. The CAISO shall not calculate and

apply a Price Correction Derived LMP for settlement of exports that are part of a Schedule that results from Bids submitted in violation of Section 30.5.5. The CAISO will calculate a Price Correction Derived LMP for each affected CAISO Demand and exports as follows: the total cleared MWhs of CAISO Demand or exports in the Day-Ahead Schedule or FMM Schedule, as applicable, multiplied by the corrected LMP, minus the make-whole payment amount, all of which is divided by the total cleared MWhs of CAISO Demand or export in the Day-Ahead Schedule or FMM Schedule, as applicable. The make-whole payment amount will be calculated on an hourly basis determined by the area between the Scheduling Coordinator's CAISO Demand or Export Bid curve and the corrected LMP, which is calculated as the MWhs for each of the cleared bid segments in the Day-Ahead Schedule or FMM Schedule for the affected resource, multiplied by the maximum of zero or the corrected LMP minus the bid segment price. For the purpose of this calculation, the CAISO will not factor in a make-whole payment amount for Self-Scheduled CAISO Demand or exports. Any non-zero amounts in revenue collected as a result of the application of the Price Correction Derived LMP will be captured through the calculation of the IFM Congestion Charge reflected in Section 11.2.4.1 and the allocation of non-zero amounts of the sum of Imbalance Energy, Uninstructed Imbalance Energy, and Unaccounted for Energy in accordance with Section 11.5.4.

* * *

11.25.1 Compensation

All resources identified as resolving the Flexible Ramping Constraint in the applicable RTUC interval are awarded Flexible Ramping Constraint capacity and will be compensated for such capacity for each RTUC interval, whether or not the Flexible Ramping Constraint is binding, limited by the quantity of Flexible Ramping Constraint requirements set by the CAISO operators as follows: The Scheduling Coordinator is paid the product of the (1) upward MW of capacity identified to satisfy the constraint, multiplied by 0.25 hours, and (2) Flexible Ramping Constraint Derived Price calculated for each applicable fifteen-minute FMM interval as described further in this Section 11.25.1. Payment to resources will be rescinded as set forth in Section 11.25.2. For each applicable fifteen-minute FMM interval, the Flexible Ramping Constraint Derived Price is

equal to the lesser of: 1) $800/MWh; or 2) the greater of: (a) zero (0), or (b) the Real-Time ASMP for Spinning Reserves for the applicable fifteen-minute FMM interval; or (c) the Flexible Ramping Constraint Shadow Price minus seventy-five (75) percent of the maximum of (i) zero (0), or (ii) the Real-Time System Marginal Energy Cost, calculated as the simple average of the System Marginal Energy Cost for each of the three five-minute RTD intervals in the applicable fifteen-minute FMM interval. The Shadow Price of the binding Flexible Ramping Constraint represents the reduction of the total Energy and Ancillary Services procurement cost associated with a marginal change of that constraint, which is equal to zero (0) if the Flexible Ramping Constraint is not binding. All costs associated with payments made pursuant to this Section 11.25 are allocated to all Scheduling Coordinators pursuant to the requirements set forth in Section 11.25.3.

11.25.2 Rescission of Payment for Non-Performance

Payments to Scheduling Coordinators are rescinded for the quantity of MWs of undelivered Flexible Ramping Constraint capacity determined as the hourly sum of the Settlement Interval amounts calculated as the minimum of: 1) the Flexible Ramping Constraint capacity identified as having contributed to the relief of the Flexible Ramping Constraint, or 2) the maximum of (a) zero (0), or (b) the difference between (i) the absolute value of the negative UIE and (ii) the upward MWs identified as Undelivered Ancillary Services Capacity as required in Section 11.10.9.3. The rescinded amounts will be based on the product of the: 1) MWs quantities to be rescinded determined as described in this Section 11.25.2; and 2) hourly Flexible Ramping Constraint price determined as the weighted average of the four fifteen-minute Flexible Ramping Constraint Derived Prices derived as described in Section 11.25.1.

* * *

11.29.5.3 Data Files

Settlement Statements relating to each Scheduling Coordinator, CRR Holder, Black Start Generator or Participating TO shall be accompanied by data files of supporting information that includes the following for each Settlement Period of the Trading Day:

(a) the aggregate quantity (in MWh) of Energy supplied or withdrawn by the Scheduling Coordinator Metered Entities represented by the Scheduling Coordinator;

(b) the aggregate quantity (in MW) and type of Ancillary Services capacity provided or purchased;

(c) the relevant prices that the CAISO has applied in its calculations;

(d) details of the scheduled quantities of Energy and Ancillary Services accepted by the CAISO in the Day-Ahead Market and the RTM;

(e) details of Imbalance Energy and penalty payments;

(f) details of the CRR Payments or CRR Charges, and any payments or charges associated with the CRR Auctions; and

(g) detailed calculations of all fees, charges and payments allocated among Scheduling Coordinators and each Scheduling Coordinator's share.

* * *

11.29.17.2.1 Methodology for Allocating Payment Default Amounts

Except as set forth in Section 11.29.17.2.2, each payment default amount allocated to CAISO Creditors through a shortfall allocation pursuant to Section 11.29.17.1 and that remains unpaid by the defaulting Scheduling Coordinator or CRR Holder will be allocated on the next practicable Invoices to the Default- Invoiced SCIDs to which the percentage shares calculated pursuant to Section 11.29.17.2.7 for the current calendar quarter apply, excluding the CAISO Debtor that has not paid the payment default amount, pursuant to the following methodology:

(a) Twenty (20) percent of the payment default amount will be allocated to the Default- Invoiced SCIDs in proportion to the net amounts that were payable in each applicable calendar quarter (and averaged within such calendar quarter) to the Default-Invoiced SCIDs over the applicable Default Look-Back Periods. For Market Participants subject to Default Election option 1, these net amounts will be calculated on an SCID-by-SCID basis. For Market Participants that are eligible for and have chosen Default Election option 2, these net amounts will be

calculated by consolidating all of the data for the applicable SCIDs, recognizing any offsetting effect of an individual SCID's positive or negative dollar amount in the consolidated total.

(b) Thirty (30) percent of the payment default amount will be allocated to the Default-Invoiced SCIDs in proportion to the sum of the absolute values of the dollar amounts shown on their Invoices payable or receivable in each applicable calendar quarter (and averaged within such calendar quarter) over the applicable Default Look-Back Periods, after excluding dollar amounts shown on the Invoices for payments and charges for GMC, RMR, and Wheeling Access Charge costs, and after excluding the billing of Access Charges and the payment of Transmission Revenue Requirements to Participating Transmission Owners. For Market Participants subject to Default Election option 1, the sum of the absolute values of the dollar amounts shown on their Invoices payable or receivable in each applicable calendar quarter will be calculated on an SCID-by-SCID basis. For Market Participants that are eligible for and have chosen Default Election option 2, the absolute values of the net sum of the dollar amounts shown on their Invoices payable or receivable in each applicable calendar quarter will be calculated by consolidating all of the data for the applicable SCIDs, recognizing any offsetting effect of an individual SCID's positive or negative dollar amount in the consolidated total.

(c) Fifty (50) percent of the payment default amount will be allocated to the Default-Invoiced SCIDs in proportion to the largest of the following five (5) amounts calculated in MWh for every month in each applicable calendar quarter (and averaged within such calendar quarter) for each Default-Invoiced SCID over the applicable Default Look-Back Periods:

(1) Cleared Day-Ahead Schedules to supply Energy, plus Day-Ahead

Ancillary Services Awards and qualified Self-Provided Ancillary Services, plus scheduled supply obligation for Ancillary Services (including imports but excluding RUC Schedules), plus Virtual Supply Awards;

(2) Metered Generation, plus Real-Time Interchange Import Schedules, plus Real-Time Ancillary Services Awards and qualified Self-Provided Ancillary Services, plus FMM Ancillary Services Awards and qualified Self-Provided Ancillary Services, plus Real-Time supply obligation for Ancillary Services;

(3) Cleared Day-Ahead Schedules for Demand (including Demand served by Pumped-Storage Hydro Units and exports) multiplied by one-hundred three (103) percent to reflect Transmission Losses, plus scheduled demand obligation for Ancillary Services, plus Virtual Demand Awards;

(4) Metered Load multiplied by one-hundred three (103) percent to reflect Transmission Losses, plus Real-Time Interchange Export Schedules, plus Real-Time demand obligation for Ancillary Services; or

(5) The greater of (A) the quantity of CRRs acquired in CRR Auctions or transferred through the Secondary Registration System (excluding CRRs acquired in CRR Allocations) or (B) Inter-SC Trades of Energy.

For Market Participants subject to Default Election option 1, each of the five (5) amounts calculated in MWh for every month in each applicable calendar quarter (and averaged within such calendar quarter) will be calculated on an SCID-by-SCID basis. For Market Participants that are eligible for and have chosen Default Election option 2, each of the five (5) amounts calculated in MWh for every month in each applicable calendar quarter (and averaged within such calendar quarter) will be calculated by consolidating all of the data for the applicable SCIDs.

* * *

11.31 Intertie Schedules Decline Charges

The Decline Potential Charge shall apply to Intertie transactions as discussed belowbelow. The Decline Potential Charge does not apply to FMM Schedules of Economic Bids, Dynamic

Transfers, and Variable Energy Resources located outside the CAISO Balancing Authority Area that have been qualified to use the forecast of their output produced by the CAISO as specified in Section 4.8.2.1.2.

(a) HASP Block Intertie Schedules: Any HASP Block Intertie Schedule for an Energy import when the HASP Block Intertie Schedule is not delivered for any reason (with no exceptions based on the circumstances of a particular failure to deliver), to the extent the decline is made prior to the start of the applicable FMM interval. The Decline Potential Charge – Exports shall apply to any HASP Block Intertie Schedule for an Energy export when the HASP Block Intertie Schedule is not delivered for any reason (with no exceptions based on the circumstances of a particular failure to deliver), to the extent the decline is made prior to the start of the applicable FMM interval. The Decline Potential Charge will not apply if the decline is made after the applicable E-tag deadline, as defined in Section 30.6.2.

(b) Economic Hourly Block Bid with Intra-Hour Option: Imports and exports accepted in an HASP Block Intertie Schedule that are incremental to Day-Ahead Schedules are subject to the Decline Potential Charge to the extent the decline is made prior to the start of the applicable FMM interval. The Decline Potential Charge will not apply if the decline is made after the applicable E-tag deadline, as defined in Section 30.6.2. To the extent the incremental import or export schedule in HASP is curtailed through the FMM, for the 15-minute FMM interval in which the resource follows the CAISO Dispatch Instructions will not be subject to the Decline Potential Charge.

(c) Variable Energy Resources outside CAISO Balancing Authority Area Using Own Forecast: Imports from Variable Energy Resources using their own forecast are subject to the Decline Potential Charge to the

extent the resource over-forecasts over the month as discussed below. For each Trading Hour, the CAISO compares the maximum 15-minute FMM Schedule (that is based on the forecast submitted 37.5 minutes prior to flow) to the maximum 15-minute advisory schedule from the Hour-Ahead Scheduling Process (based upon the hourly forecast received 75 minutes prior to flow) and calculates the differences between the two. These hourly differences are summed over the month. If the maximum advisory schedule exceeds the actual financially binding schedule by the relevant threshold over the course of the month, the Decline Potential Charge applies.

(d) Decline Potential Charge: For any Settlement Interval, the Decline Potential Charge – Imports or Decline Potential Charge – Exports, as the case may be, shall equal the MWh quantity of the import or export not delivered multiplied by the greater of $10/MWh or fifty percent (50%) of the FMM LMP. The Decline Potential Charge – Imports and Decline Potential Charge – Exports will be calculated for each HASP Block Intertie Schedule or VER Self-Schedule that is not delivered, provided that only the Decline Monthly Charge – Imports and Decline Monthly Charge – Exports shall be payable by the Scheduling Coordinator as described in Section 11.31.1.

11.31.1 Decline Monthly Charge – Imports

The Decline Monthly Charge – Imports shall be applied to each Scheduling Coordinator on the Settlement Statements issued for the last Trading Day of each Trading Month, and shall be the sum of the Scheduling Coordinator's Decline Potential Charges – Imports for each Settlement Period during that Trading Month multiplied by a ratio. The ratio will represent the portion of the Scheduling Coordinator's declined HASP Block Intertie Schedules for Energy imports or the VER Self-Schedules that exceed during the Trading Month the applicable exemption threshold described in Section 11.31.1 and Section 11.31.2.

(a) The ratio will be calculated as follows:

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

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

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

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

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

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

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

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

11.31.2 Decline Monthly Charge – Exports

The Decline Monthly Charge – Exports shall be applied to each Scheduling Coordinator on the Settlement Statements issued for the last Trading Day of each Trading Month, and shall be the sum of the Scheduling Coordinator's Decline Potential Charges – Exports for each Settlement Interval during that Trading Month multiplied by a ratio. The ratio will represent the portion of the

Scheduling Coordinator's declined HASP Block Intertie Schedules for Energy exports that exceed the applicable exemption threshold during the Trading Month.

(a) The ratio will be calculated as follows:

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

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

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

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

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

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

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

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

11.32 Measures to Address Intertie Scheduling Practices

The CAISO will take the following actions regarding Schedules that clear the Day-Ahead Market at the Interties and that are wholly or partially reversed through a FMM Schedule:

(i) The CAISO will charge the Scheduling Coordinator the positive difference between the Day-Ahead Market price and the FMM LMP applicable to any imports that clear the Day-Ahead Market and are reduced through a Bid to the RTM if the Scheduling Coordinator either: (a) fails to submit an E-Tag or E-Tags consistent with the Scheduling Coordinator's Day-Ahead Schedule and WECC scheduling criteria; or (b) withdraws the E-Tag or E-Tags prior to forty-five (45) minutes before the Trading Hour.

(ii) The CAISO will charge the Scheduling Coordinator the positive difference between the FMMLMP and the Day-Ahead Market LMP applicable to any exports that clear the Day-Ahead Market and are reduced through a Bid to the RTM if the Scheduling Coordinator either: (a) fails to submit an E-Tag or E-Tags consistent with the Scheduling Coordinator's Day-Ahead Schedule and WECC scheduling criteria; or (b) withdraws the E-Tag or E-Tags prior to forty-five (45) minutes before the Trading Hour.

(iii) The CAISO will treat any reduction by a Scheduling Coordinator to a Day-Ahead import or export Schedule through a Bid to the RTM as a Virtual Award for purposes of adjusting CRR Revenue pursuant to Section 11.2.4.6 if the Scheduling Coordinator submits Schedules on behalf of or is a CRR Holder.

(iv) For any import Schedule that clears the Day-Ahead Market which a Scheduling Coordinator reduces through a Bid to the RTM, such reduced quantities will be subject to the allocation of Net RTM Bid Cost Uplift as set forth in Section 11.8.6.6.

(v) The provisions of this Section 11.32 will not apply to Schedules that clear the Day-Ahead Market at the Scheduling Points and that a Scheduling

Coordinator wholly or partially reverses through a Bid to the RTM to the extent such Schedules are valid and balanced ETC, TOR, or Converted Rights Self-Schedules in the Day-Ahead Market.

11.33 Settling Revenue from Schedule Sourcing/Sinking in Same BAA

The import portion of any Schedule resulting from Bids submitted in violation of Section 30.5.5 will be settled at the lower of the: (a) LMP of the Scheduling Point for the import portion of the Schedule in the market in which the import portion of the Schedule was awarded; or (b) LMP of the Scheduling Point for the export portion of the Schedule in the market in which the export portion of the Schedule was awarded. Such settlement will occur irrespective of whether the import and export were scheduled in the same market or are split between the Day-Ahead Market and the Real-Time Market.

* * *

16.4.5 TRTC Instructions Content

TRTC Instructions will include the following information at a minimum and such other information as the CAISO may reasonably require the Participating TO to provide to enable the CAISO to carry out its functions under the CAISO Tariff, Operating Procedures and Business Practice Manuals:

(1) A unique Contract Reference Number for each source and sink combination applicable to the Existing Contract (i.e., the CRN that will be assigned by the CAISO and communicated to the Participating TO that references a single Existing Contract or a set of interdependent Existing Contracts for each source and sink combination);

(2) Whether the instruction can be exercised independent of the CAISO's day-to-day involvement ("Yes/No");

(3) Name of an operational single point of contact for instructions and a 24-hour a day telephone number for the Participating TO contact for Existing Contract issues or the agreed upon party;

(4) Name(s) and number(s) of Existing Contract(s) that are represented by the unique CRN;

(5) The following information as stored in the Master File: (a) the applicable Point(s) of Receipt and Point(s) of Delivery); (b) for each Point of Receipt, the resource names for the physical resources as the eligible sources (eligible physical sources include Generating Units and System Resources), and for each Point of Delivery, the resource names for the physical resources as the eligible sinks (eligible physical sinks include Load PNodes, Custom Load Aggregation Points and System Resources); (c) for each physical source or sink, the maximum Existing Rights capacity (MW) that can be scheduled as an Existing Right under the Existing Contract; and (d) for each physical source and sink, the Scheduling Coordinator(s) and their Business Associate Identification (BAID) that is(are) eligible to submit ETC Self-Schedules utilizing these sources and sinks;

(6) Names of the party(ies) to the Existing Contract(s);

(7) The Scheduling Coordinator BAID that is entitled to the Settlement of reversal of Congestion Charges;

(8) Type(s) of service rights by the holder of the Existing Rights, by type of service (firm, conditional firm, or non-firm), with priorities for firm and conditional firm transmission services and maximum amounts of service rights in MW;

(9) Instructions for the allowable timeframes at which the ETC Self-Schedules and ETC Self-Schedule changes may be submitted to the CAISO, which include whether the Scheduling Coordinator may submit ETC Self-Schedules or ETC Self-Schedule changes: (a) into the DAM;(b) into the RTM; (c) after the close of submitting Bids into the RTM, but before twenty (20) minutes before the applicable Trading

Hour of the Trading Day; and (d) at or after twenty (20) minutes before the applicable Trading Hour of the Trading Day; in addition, the TRTC Instructions may also include any additional comments and restrictions on the submission time of ETC Self- Schedules and ETC Self-Schedule changes;

(10) Term or service period(s) of the Existing Contract(s);

(11) Any special procedures that would require the CAISO to implement curtailments in any manner different from pro rata reduction of the transfer capability of the transmission line; any such TRTC Instructions submitted to the CAISO must be clear, unambiguous, and not require the CAISO to make any judgments or interpretations as to the meaning intent, results, or purpose of the curtailment procedures or the Existing Contract and the section of the Existing Contract that provides this right for reference, otherwise, they will not be accepted by the CAISO;

(12) The forecasted usage patterns for each Existing Contract for the upcoming annual period of the annual CRR release processes as well as for the upcoming monthly period of the monthly CRR release processes, which will consist of hourly MWh data over the whole year for those resources that will use the Existing Contract; this information will be considered by the CAISO in managing its accounting for usage of Existing Rights in the release of CRRs; this information shall not be used by the CAISO to validate ETC Self-Schedules when submitted by Scheduling Coordinators and therefore shall not affect the Existing Rights holder's ability to utilize its rights under the Existing Contract;

(13) Whether or not the Existing Contract provides for the right to self-provide Ancillary Services; and

(14) Specification of any contract requirements in the ETC that warrants special consideration in the implementation of the physical rights under the ETC.

* * *

16.5 Treatment Of Existing Contracts For Transmission Service

The CAISO will accommodate Existing Rights, so that the holders of Existing Rights will receive the same priorities (in scheduling, curtailment, assignment and other aspects of transmission system usage) to which they are entitled under their Existing Contracts.

In addition, scheduling deadlines and operational procedures associated with Existing Rights will be honored by the CAISO, provided such information is explicitly included in the TRTC Instructions. The CAISO will accommodate and honor Existing Rights as follows:

(1) For Existing Rights that permit Interchange Schedule changes over Scheduling Points with other Balancing Authority Areas, the CAISO will reserve transmission capacity equal to the Existing Rights transmission capacity and make a corresponding adjustment in its determination of ATC. For Existing Rights that permit Interchange Schedule changes after the Market Close of the Day-Ahead Market, the CAISO will reserve transmission capacity equal to the unscheduled ETC amount of transmission capacity for that Scheduling Point.

(2) For Existing Rights within the CAISO Balancing Authority Area, the CAISO will not set-aside capacity associated with the Existing Rights transmission capacity.

(3) In the RTM, the CAISO will give valid ETC Self-Schedules priority over other non-ETC Day-Ahead Schedules and RTM Bids. In the event of a reduction in capacity on the transmission path associated with the Existing Right, the CAISO will honor the Existing Rights priority in accordance with this Section 16.

(4) When the Existing Contract permits, the CAISO will allow the holder of Existing Rights to make changes to the scheduled amounts of Supply after the submission of HASP ETC Self-Schedules in accordance with the TRTC Instructions established for such changes. The CAISO will, as necessary, redispatch non-ETC resources to accommodate valid ETC Self-Schedule changes in Real-Time.

(5) All contractual provisions that have been communicated to the CAISO in writing in accordance with this Section 16 by the parties to the Existing Contracts, shall be honored by the CAISO and the parties to the Existing Contracts and shall be implemented by the CAISO in accordance with the terms and conditions of the relevant Existing Contracts so notified.

16.5.1 System Emergency Exceptions

As set forth in Section 4.2.1, all Market Participants, including Scheduling Coordinators, Utility Distribution Companies, Participating TOs, Participating Generators (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area), Participating Loads, Demand Response Providers, Balancing Authorities (to the extent the agreement between the Balancing Authority and the CAISO so provides), and MSS Operators within the CAISO Balancing Authority Area and all System Resources must comply fully and promptly with CAISO Dispatch Instructions and operating orders, unless such operation would impair public health or safety. The CAISO will honor the terms of Existing Contracts, provided that in a System Emergency and circumstances in which the CAISO considers that a System Emergency is imminent or threatened, holders of Existing Rights must follow CAISO operating orders even if those operating orders directly conflict with the terms of Existing Contracts, unless such operating orders are inconsistent with the terms of an agreement between the CAISO and a Balancing Authority. In the event of a conflict between the CAISO Tariff and an agreement between the CAISO and a Balancing Authority, the agreement will govern. For this purpose CAISO operating orders to shed Load shall not be considered as an impairment to public health or safety. This

section does not prohibit a Scheduling Coordinator from modifying its Bid or re-purchasing Energy in the Real-Time Market.

* * *

16.9.1 Scheduling Deadlines

Those holders of Existing Rights who have Existing Rights as reflected in the TRTC Instructions that allow scheduling after the close of the Day-Ahead Market may submit ETC Self-Schedules for the use of those rights by the deadline for the Market Close for RTM. Submission of schedule changes beyond the Market Close for RTM that are permitted pursuant to the terms of the applicable ETC, shall not be deemed to be an unbalanced ETC Self-Schedule for the purposes of Settlement, consistent with the ETC and TOR Self-Schedule Settlement treatment described in Section 11.5.7..

* * *

16.11 Inter-Balancing Authority Area ETC Self-Schedule Bid Changes

Changes to ETC Self-Schedules that occur during the CAISO's Real-Time Market that involve changes to CAISO Balancing Authority Area imports or exports with other Balancing Authority Areas (that is, inter-Balancing Authority Area changes to ETC Self-Schedules) will be allowed and will be recorded by the CAISO based upon notification received from the Scheduling Coordinator representing the holder of the Existing Rights. The Scheduling Coordinator representing the holder of the Existing Right must notify the CAISO of any such changes to external import/export in submitted ETC Self-Schedules. The Scheduling Coordinator representing the holder of the Existing Right must notify the CAISO of Real-Time Market changes to external import/export Interchange Schedules in submitted ETC Self-Schedules, by telephone. The timing and content of any such notification must be consistent with the TRTC Instructions previously submitted to the CAISO by the Responsible PTO. The CAISO will manually adjust or update the FMM Schedule for the Scheduling Coordinator to conform with the other Balancing Authority Area's net ETC Self-Schedule in Real-Time, and the notifying Scheduling Coordinator will be responsible for and manage any resulting Energy imbalance. These Imbalance Energy

deviations will be priced and charged to the Scheduling Coordinator representing the holder of Existing Rights in accordance with the FMM LMP.

* * *

17.1.4 TRTC Instructions Content

TRTC Instructions will include the following information at a minimum and such other information as the CAISO may reasonably require the Non-Participating TO holder of a TOR to provide to enable the CAISO to carry out its functions under the CAISO Tariff, Operating Procedures and Business Practice Manuals:

(1) A unique Contract Reference Number for each source and sink combination applicable to the TOR (i.e., the CRN that will be assigned by the CAISO and communicated to the Non-Participating TO that references a single TOR or a set of interdependent TORs for each source and sink combination);

(2) Whether the instruction can be exercised independent of the CAISO's day-to-day involvement ("Yes/No");

(3) Name of an operational single point of contact for instructions and a 24- hour a day telephone number for the Non-Participating TO contact for TOR issues or the agreed upon party;

(4) Name(s) and number(s) of TOR(s) that are represented by the unique CRN;

(5) The following information, as stored in the Master File: (a) the applicable Point(s) of Receipt and Point(s) of Delivery); (b) for each Point of Receipt, the resource names for the physical resources as the eligible sources (eligible physical sources include Generating Units and System Resources), and for each Point of Delivery, the resource names for the physical resources as the eligible sinks (eligible physical sinks include Load PNodes, Custom Load Aggregation Points and System Resources); (c) for each physical source or sink, the maximum capacity

(MW) that can be scheduled as a TOR; and (d) for each physical source and sink, the Scheduling Coordinator(s) and their Business Associate Identification (BAID) that is (are) eligible to submit TOR Self-Schedules utilizing these sources and sinks;

(6) Names of the party(ies) holding the TOR(s) and the parties to any agreements applicable to the TORs;

(7) The Scheduling Coordinator BAID that is entitled to the Settlement of reversal of Congestion Charges;

(8) Amount of TORs, in maximum MW, that may be utilized under the relevant TRTC Instructions;

(9) Instructions for the allowable timeframes at which the TOR Self-Schedules and TOR Self-Schedule changes may be submitted to the CAISO, which include whether the Scheduling Coordinator may submit TOR Self-Schedules or TOR Self-Schedule changes: (a) into the DAM; (b) into the RTM; (c) after the close of submitting Bids into the RTM, but before twenty (20) minutes before the applicable Trading Hour of the Trading Day; and (d) at or after twenty (20) minutes before the applicable Trading Hour of the Trading Day; in addition, the Non-Participating TO may also provide any additional comments and restrictions on the submission time of TOR Self- Schedules and TOR Self-Schedule changes;

(10) Term of ownership interest in the TOR(s) and of any agreements applicable to the TOR(s);

(11) Any special procedures that would require the CAISO to implement curtailments in any manner different than pro rata reduction of the transfer capability of the transmission line; any such instructions submitted to the CAISO must be clear, unambiguous, and not require the CAISO to make any judgments

or interpretations as to the meaning, intent, results, or purpose of the curtailment procedures or of any applicable Existing Contract, otherwise, they will not be accepted by the CAISO; and

(12) Whether or not the TOR provides the right to self-provide Ancillary Services.

* * *

17.2 Treatment Of TORs

The CAISO will accommodate TORs, so that the holders of TORs will receive the same priorities (in scheduling, curtailment, assignment and other aspects of transmission system usage) to which they are entitled under any applicable Existing Contracts or other agreements pertaining to the operation of their TORs.

In addition, scheduling deadlines and operational procedures associated with TORs will be honored by the CAISO, provided such information is explicitly included in the TRTC Instructions.

The CAISO will accommodate and honor TORs as follows:

(1) The CAISO will reserve transmission capacity equal to the TOR transmission capacity and make a corresponding adjustment in its determination of ATC. The CAISO will not limit parallel flow from flowing on TOR transmission capacity consistent with the redispatch provisions of Section 17.2(3), just as the CAISO does not limit TOR Self-Schedules from flowing on non-TOR transmission. There shall be no compensation for parallel flow for either the CAISO or the TOR holder.

(2) In the RTM, the CAISO will give valid TOR Self-Schedules priority over other non-TOR Day-Ahead Schedules and RTM Bids. In the event of a reduction in capacity on the transmission path associated with the TOR, the CAISO will honor the TOR priority in accordance with this Section 17.

(3) The CAISO will allow the holder of a TOR to make changes to the scheduled amounts of supply after the submission of HASP TOR Self-

Schedules in accordance with the TRTC Instructions established for such changes. The CAISO will, as necessary, redispatch non-TOR resources to accommodate valid TOR Self-Schedule changes in Real- Time.

(4) The CAISO will allow the holder of a TOR to self-provide Ancillary Services, which will include the ability of the holder of a TOR to import Ancillary Services at Scheduling Points with the CAISO.

(5) The submission of a TOR Self-Schedule change that is authorized pursuant to an applicable existing agreement shall not affect the application of the IFM Congestion Credit or the RTM Congestion Credit, and the IFM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules or the RTM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules for a TOR Self-Schedule that satisfies the applicable requirements of Sections 17.4.1 and 17.5.

17.2.1 System Emergency Exceptions

As set forth in Section 4.2.1, all Market Participants, including Scheduling Coordinators, Utility Distribution Companies, Participating TOs, Participating Generators(which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area), Participating Loads, Demand Response Providers, Balancing Authorities (to the extent the agreement between the Balancing Authority and the CAISO so provides), and MSS Operators within the CAISO Balancing Authority Area and all System Resources must comply fully and promptly with the CAISO's Dispatch Instructions and operating orders, unless such operation would impair public health or safety.

The CAISO will honor the terms of TORs, provided that in a System Emergency and circumstances in which the CAISO considers that a System Emergency is imminent or threatened, to enable the CAISO to exercise its responsibilities as Balancing Authority in accordance with Applicable Reliability Criteria, holders of TORs must follow CAISO operating orders even if those operating orders directly conflict with the terms of applicable Existing

Contracts or any other contracts pertaining to the TORs, unless such operating orders are inconsistent with the terms of an agreement between the CAISO and a Balancing Authority. In the event of a conflict between the CAISO Tariff and an agreement between the CAISO and a Balancing Authority, the agreement will govern. For this purpose CAISO operating orders to shed Load shall not be considered as an impairment to public health or safety. This section does not prohibit a Scheduling Coordinator from modifying its Bid or re-purchasing Energy in the RTM.

* * *

17.4.1 Scheduling Deadlines

Holders of TORs may submit TOR Self-Schedules for the use of those rights by the deadline for the Market Close for the RTM.

* * *

17.6 Inter-Balancing Authority Area TOR Self-Schedule Bid Changes

Changes to TOR Self-Schedules that occur during the CAISO's Real-Time Market that involve changes to CAISO Balancing Authority Area imports or exports with other Balancing Authority Areas (that is, inter-Balancing Authority Area changes to TOR Self-Schedules) will be allowed and will be recorded by the CAISO based upon notification received from the Scheduling Coordinator representing the holder of the TOR. The Scheduling Coordinator representing the holder of the TOR must notify the CAISO of any such changes to external import/export in submitted TOR Self-Schedules. The Scheduling Coordinator representing the holder of the TOR must notify the CAISO of Real-Time Market changes to external import/export Interchange Schedules in submitted TOR Self-Schedules, by telephone. The timing and content of any such notification must be consistent with the TRTC Instructions previously submitted to the CAISO by the Non-Participating TO. The CAISO will manually adjust or update the FMM Schedule for the Scheduling Coordinator to conform with the other Balancing Authority Area's net TOR Self-Schedule in Real-Time, and the notifying Scheduling Coordinator will be responsible for and manage any resulting Energy imbalance. These Imbalance Energy deviations will be priced and charged to the Scheduling Coordinator representing the holder of the TOR in accordance with

the FMM LMP.

* * *

27 CAISO Markets And Processes

In the Day-Ahead and Real-Time time frames the CAISO operates a series of procedures and markets that together comprise the CAISO Markets Processes. In the Day-Ahead time frame, the CAISO conducts the Market Power Mitigation (MPM) process, the Integrated Forward Market (IFM) and the Residual Unit Commitment (RUC) process. In the Real-Time time frame, the CAISO does the following: 1)accepts the Economic Bids and Self-Schedules used in the Real-Time Market procedures, 2) conducts the MPM process for the RTM, 3) accepts and awards HASP Block Intertie Schedules for Energy and Ancillary Services, 4) provides HASP Advisory Schedules for Energy and Ancillary Services for Bids that do not create a HASP Block Intertie Schedule, 5) conducts the Real-Time Unit Commitment (RTUC), 6) conducts the Short-Term Unit Commitment (STUC), 7) conducts the Fifteen Minute Market (FMM), and 8) conducts the five-minute Real-Time Dispatch (RTD). As appropriate, the CAISO Markets Processes utilize transmission and Security Constrained Unit Commitment and dispatch algorithms in conjunction with a Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 to optimally commit, schedule and Dispatch resources and determine marginal prices for Energy, Ancillary Services and RUC Capacity. Congestion Revenue Rights are available and entitle holders of such instruments to a stream of hourly payments or charges associated with revenue the CAISO collects or pays from the Marginal Cost of Congestion component of hourly Day-Ahead LMPs. Through the operation of the CAISO Markets Processes the CAISO develops Day-Ahead Schedules, Day-Ahead AS Awards and RUC Schedules, , HASP Block Intertie Schedules for Energy and AS Awards, HASP Advisory Schedules, FMM Energy Schedules, and FMM Ancillary Services Awards, Real-Time AS Awards and Dispatch Instructions to ensure that sufficient supply resources are available in Real-Time to balance Supply and Demand and operate in accordance with Reliability Criteria.

* * *

27.1.1 Locational Marginal Prices For Energy

As further described in Appendix C, the LMP for Energy at any PNode is the marginal cost of serving the next increment of Demand at that PNode consistent with existing Transmission Constraints and the performance characteristics of resources, also considering, among other things, Energy Bid Curves. The LMP at any given PNode is comprised of three cost components: the System Marginal Energy Cost (SMEC); Marginal Cost of Losses (MCL); and Marginal Cost of Congestion (MCC). The IFM calculates LMPs for each Trading Hour of the next Trading Day. The FMM calculates distinct financially binding fifteen-minute LMPs for each of the four fifteen-minute intervals within a Trading Hour. The Real-Time Dispatch runs every five (5) minutes throughout each Trading Hour and calculates five-minute LMPs for the next Dispatch Interval. The CAISO uses the FMM or RTD LMPs for Settlements of the Real-Time Market. In the event that a Pricing Node becomes electrically disconnected from the market model during a CAISO Market run, the LMP, including the SMEC, MCC and MCL, at the closest electrically connected Pricing Node will be used as the LMP at the affected location.

*** * ***

27.1.2.1 Ancillary Service Marginal Prices – Sufficient Supply

As provided in Section 8.3, Ancillary Services are procured and awarded through the IFM and the FMM, and the CAISO also accepts and awards HASP Block Intertie Schedules for Ancillary Services in HASP. Ancillary Services awarded through HASP are made financially binding in the FMM. The IFM calculates hourly Day-Ahead Ancillary Service Awards and establishes Ancillary Service Marginal Prices (ASMPs) for the accepted Regulation Up, Regulation Down, Spinning Reserve and Non-Spinning Reserve Bids. The IFM co-optimizes Energy and Ancillary Services subject to resource, network and regional constraints. In the HASP, the CAISO accepts and awards Ancillary Services from HASP Block Intertie Schedules for the next Trading Hour as described in Section 34.2. The CAISO calculates the price for the settlement of Ancillary Services accepted and awarded in HASP based on the FMM ASMP as described herein and further described in Section 34.4. The FMM process that is performed every fifteen (15) minutes establishes fifteen (15) minute Ancillary Service Schedules, Awards, and prices for the upcoming

quarter of the given Trading Hour. ASMPs are determined by first calculating Shadow Prices of Ancillary Services for each Ancillary Service type and the applicable Ancillary Services Regions. The Ancillary Services Shadow Prices are produced as a result of the co-optimization of Energy and Ancillary Services through the IFM and the Real-Time Market, subject to resource, network, and requirement constraints. The Ancillary Services Shadow Prices represent the marginal cost of the relevant binding regional constraints at the optimal solution, or the reduction of the combined Energy and Ancillary Service procurement cost associated with a marginal relaxation of that constraint. If the constraint for an Ancillary Services Region is not binding, the corresponding Ancillary Services Shadow Price in the Ancillary Services Region is zero (0). During periods in which supply is sufficient, the ASMP for a particular Ancillary Service type and Ancillary Services Region is then the sum of the Ancillary Services Shadow Prices for the specific type of Ancillary Service and all the other types of Ancillary Services for which the subject Ancillary Service can substitute, as described in Section 8.2.3.5, for the given Ancillary Service Region and all the other Ancillary Service Regions that include that given Ancillary Service Region. During periods in which supply is insufficient, the ASMP for a particular Ancillary Service type and Ancillary Services Region will reflect the Scarcity Reserve Demand Curve Values set forth in Section 27.1.2.3.

27.1.2.2 Opportunity Cost in ASMP

The Ancillary Services Shadow Price, which, as described above, is a result of the Energy and Ancillary Service co-optimization, includes the foregone opportunity cost of the marginal resource, if any, for not providing Energy or other types of Ancillary Services the marginal resource is capable of providing in the relevant market. The ASMPs determined by the IFM or FMM optimization process for each resource whose Ancillary Service Bid is accepted will be no lower than the sum of (i) the Ancillary Service capacity Bid price submitted for that resource, and (ii) the foregone opportunity cost of Energy in the IFM or FMM for that resource. The foregone opportunity cost of Energy for this purpose is measured as the positive difference between the IFM or FMM LMP at the resource's Pricing Node and the resource's Energy Bid price. If the resource's Energy Bid price is higher than the LMP, the opportunity cost measured for this

calculation is $0. If a resource has submitted an Ancillary Service Bid but no Energy Bid and is under an obligation to offer Energy in the Day-Ahead Market (e.g. a non-hydro Resource Adequacy Resource), its Default Energy Bid will be used, and its opportunity cost will be calculated accordingly. If a resource has submitted an Ancillary Service Bid but no Energy Bid and is not under an obligation to offer Energy in the Day-Ahead Market, its Energy opportunity cost measured for this calculation is $0 since it cannot be dispatched for Energy. For Self-Scheduled Hourly Block Bids for Ancillary Services awarded in HASP, the opportunity cost measured for this purpose is $0 because, as provided in Section 34.2.3**,** the CAISO cannot Schedule Energy in HASP from the Energy Bid under the same Resource ID as the submitted Ancillary Service Bid.

* * *

27.2.2.2 Real-Time Market LAP Prices

The Default LAP Hourly Real-Time Prices and the Custom LAP Hourly Real-Time Prices are calculated as described below and in Section 11.5.2.2.

27.2.2.2.1 Default LAP Pricing

The FMM and RTD Default LAP Price for a fifteen-minute FMM interval and five minute Dispatch Interval is the price as produced by the FMM and RTD optimization runs, respectively, based on the distribution of system Load at the constituent Pricing Nodes within the applicable Default LAP and is determined by the effectiveness of the Load within the Default LAP in relieving a Transmission Constraint within the effectiveness threshold as specified in Section 27.3.4.6. The Default LAP Hourly Real-Time Price is then determined for Settlement purposes as further described in Section 11.5.2.2.

27.2.2.2.2 Custom LAP Pricing

The FMM and RTD LAP Prices for Settlement of Demand at Custom LAPs for a given fifteen-minute FMM interval and five minute Dispatch interval are calculated as a Load-weighted average of the individual FMM and RTD LMPs at the PNodes within the Custom LAP, respectively, where the weights are calculated based on Meter Data. The Custom LAP Hourly Real-Time Price is then determined for Settlement purposes as further described in Section 11.5.2.2.

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27.4.1 Security Constrained Unit Commitment

The CAISO uses SCUC to run the MPM process associated with the DAM and the RTM. SCUC is conducted over multiple varying intervals to commit and schedule resources as follows: (1) in the Day-Ahead time frame, to meet Demand reflected in Bids submitted in the Day-Ahead Market and considered in the MPM process and IFM, and to procure AS in the IFM; (2) to meet the CAISO Forecast Of CAISO Demand in the RUC, HASP, STUC and FMM, and in the MPM process utilized in the HASP and RTM; and (3) to procure any incremental AS in the RTM . In the Day-Ahead MPM, IFM and RUC processes, the SCUC commits resources over the twenty-four (24) hourly intervals of the next Trading Day. In the FMM, which runs every fifteen (15) minutes and commits resources for the RTM, the SCUC optimizes over a number of 15-minute intervals corresponding to the Trading Hours for which the Real-Time Markets have closed. The Trading Hours for which the Real-Time Markets have closed consist of (a) the Trading Hour in which the applicable run is conducted and (b) all the fifteen-minute intervals of the entire subsequent Trading Hour. In the HASP, which runs once per hour, the SCUC: 1) accepts and awards HASP Block Intertie Schedules for Energy and Ancillary Services, respectively; 2) provides HASP Advisory Schedules to Economic Hourly Block Bids with Intra-Hour Option that will change for economic reasons at most once in the Trading Hour; and 3) provides HASP Advisory Schedules to all other participants in the RTM. In the STUC, which runs once an hour, the SCUC commits resources over the last fifteen (15) minutes of the imminent Trading Hour and the entire next four Trading Hours. The CAISO will commit Extremely Long Start Resources, for which commitment in the DAM does not provide sufficient time to Start-Up and be available to supply Energy during the next Trading Day as provided in Section 31.7.

* * *

27.4.3.1 Scheduling Parameters for Transmission Constraint Relaxation

In the IFM, the internal Transmission Constraint scheduling parameter is set to $5000 per MWh for the purpose of determining when the SCUC and SCED software in the IFM will relax an internal Transmission Constraint rather than adjust Supply or Demand bids or Non-priced

Quantities as specified in Sections 31.3.1.3, 31.4 and 34.12 to relieve Congestion on the constrained facility. This scheduling parameter is set to $1,500 per MWh for the RTM. The effect of this scheduling parameter value is that if the optimization can re-dispatch resources to relieve Congestion on a Transmission Constraint at a cost of $5000 per MWh or less for the IFM (or $1,500 per MWh or less for the RTM), the Market Clearing software will utilize such re-dispatch, but if the cost exceeds $5000 per MWh in the IFM (or $1,500 per MWh for the RTM) the market software will relax the Transmission Constraint. The corresponding scheduling parameter in RUC is set to $1250 per MWh.

* * *

27.5.1.1 Base Market Model used in the CAISO Markets

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

Certain external loops are modeled, which allows the CAISO to increase the accuracy of the Congestion Management process. Resources are modeled at the appropriate network Nodes. The pricing Location (PNode) of a Generating Unit generally coincides with the Node where the relevant revenue quality meter is connected or corrected, to reflect the point at which the Generating Unit is connected to the CAISO Controlled Grid. The Dispatch, Schedule, and LMP of a Generating Unit refers to a PNode, but the Energy injection is modeled in the Base Market Model for network analysis purposes at the corresponding Generating Unit's physical interconnection point), taking into account any losses in the non-CAISO Controlled Grid leading to the point where Energy is delivered to CAISO Controlled Grid. Based on the Base Market Model, the market models used in each of the CAISO markets incorporate physical characteristics needed for determining Transmission Losses and model Transmission Constraints within the CAISO Balancing Authority Area, which are then reflected in the Day-Ahead Schedules, AS Awards and RUC Awards, FMM Schedules, Dispatch Instructions, and LMPs resulting from each CAISO Markets Process. The Dispatch, Schedule, and LMP of a Dynamic System Resource or Pseudo-Tie of a Generating Unit to the CAISO Balancing Authority Area refer to a PNode, or Aggregated Pricing Node, if applicable, of the resource at its physical location in the external transmission systems that are modeled in the Base Market Model, subject to the modeling of Transmission Losses in the portions of the FNM and exclusion of such Transmission Losses' effects on the LMPs that are external to the CAISO Balancing Authority Area described in this Section 27.5.1.1. The LMP price thus associated with a Dynamic System Resource or Pseudo-Tie Generating Unit will be used for Settlement of Energy and will include the Marginal Cost of Congestion and Marginal Cost of Losses components of the LMP to that Dynamic System Resource or Pseudo-Tie Generating Unit point, excluding losses and congestion external to the CAISO Balancing Authority Area, in accordance with this Section 27.5.1.1. Further, in formulating the market models for the RTM processes, the Real-Time power flow parameters developed from the State Estimator are applied to the Base Market Model.

27.5.2 Metered Subsystems

The FNM includes a full model of MSS transmission networks used for power flow calculations and Congestion Management in the CAISO Markets Processes. Transmission Constraints (i.e. circuit ratings, thermal ratings, etc.) within the MSS, or at its boundaries, that are modeled in the Base Market Model shall be monitored but not enforced in operation of the CAISO Markets. If overloads are observed in the forward markets, are internal to the MSS or at the MSS boundaries, and are attributable to MSS operations, the CAISO shall communicate such events to the Scheduling Coordinator for the MSS and coordinate any manual Re-dispatch required in Real-Time. If, independent of the CAISO, the Scheduling Coordinator for the MSS is unable to resolve Congestion internal to the MSS or at the MSS boundaries in Real-Time, the CAISO will use Exceptional Dispatch Instructions on resources that have been bid into the RTM to resolve the Congestion. The costs of such Exceptional Dispatch will be allocated to the responsible MSS Operator. Consistent with Section 4.9, the CAISO and MSS Operator shall develop specific procedures for each MSS to determine how Transmission Constraints will be handled.

* * *

27.5.6 Management & Enforcement of Constraints in the CAISO Markets

The CAISO operates the CAISO Markets through the use of a market software system that utilizes various information including the Base Market Model, the State Estimator, submitted Bids including Self-Schedules, Generated Bids, and Transmission Constraints, including Nomograms and Contingencies transmission and generation Outages. The market model used in each of the CAISO Markets is derived from the most current Base Market Model available at that time. To create a more relevant time-specific network model for use in each of the CAISO Markets, the CAISO will adjust the Base Market Model to reflect Outages and derates that are known and applicable when the respective CAISO Market will operate, and to compensate for observed discrepancies between actual real-time power flows and flows calculated by the market software. Through this process the CAISO creates the market model to be used in each Day-Ahead Market and each process of the Real-Time Market. The CAISO will manage the enforcement of Transmission Constraints, including Nomograms and

Contingencies, consistent with good utility practice, to ensure, to the extent possible, that the market model used in each market accurately reflects all the factors that contribute to actual Real-Time flows on the CAISO Controlled Grid and that the CAISO Market results are better aligned with actual physical conditions on the CAISO Controlled Grid. In operating the CAISO Markets, the CAISO may take the following actions so that, to the extent possible, the CAISO Market solutions are feasible, accurate, and consistent with good utility practice:

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

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

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

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

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

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

* * *

27.7.3 Constrained Output Generators In The IFM

In the IFM, resources electing COG status are modeled as though they are not constrained and can operate flexibly between zero (0) and their PMax. A COG is eligible to set IFM LMPs based on its Calculated Energy Bid in any Settlement Period in which a portion of its output is needed as a flexible resource to serve Demand. A COG is not eligible for recovery of Minimum Load Costs or BCR in the IFM due to the conversion of its Minimum Load Cost to an Energy Bid and its treatment by the IFM as a flexible resource. A COG is eligible for Start-Up Cost recovery based on its Commitment Period as determined in the IFM, RUC, STUC or RTUC.

* * *

27.7.5 Constrained Output Generators In The Real-Time Market

A COG that can be started up and complete its Minimum Run Time within a five-hour period can be committed by the STUC. A COG that can be started up within the applicable RTUC run as described in Section 34.3 can be committed by the RTUC. The RTD will dispatch a COG up to its PMax or down to zero (0) to ensure a feasible Real-Time Dispatch. The COG is eligible to set the RTM LMP in any Dispatch Interval in which a portion of its output is needed to serve Demand, not taking into consideration its Minimum Run Time constraint. For the purpose of making this determination and setting the RTM LMP, the CAISO treats a COG as if it were flexible with an infinite Ramp Rate between zero (0) and its PMax, and uses the COG's Calculated Energy Bid. In any Dispatch Interval where none of the output of a COG is needed as a flexible resource to serve Demand, the CAISO shall not dispatch the unit. In circumstances in which the output of the COG is not needed as a flexible resource to serve Demand, but the unit nonetheless is online as a result of a previous commitment or Dispatch Instruction by the CAISO, the COG is eligible for Minimum Load Cost compensation.

* * *

27.9 Non-Generator Resources MWh Constraints

THIS TARIFF SECTION WILL BECOME EFFECTIVE ON NOVEMBER 27, 2012.

The CAISO will observe Non-Generator Resources' MWh constraints in the IFM as part of the co-optimization unless the resources are using Regulation Energy Management. The CAISO will observe Non-Generator Resources' MWh constraints in RUC as part of the co-optimization unless the resources are using Regulation Energy Management. The CAISO will observe Non-Generator Resources' MWh constraints in Real-Time Unit Commitment and FMM as part of the co-optimization unless the resources are using Regulation Energy Management. The CAISO will observe Non-Generator Resources' MWh constraints in Real-Time Dispatch, including constraints of resources using Regulatory Energy Management

* * *

27.10 Flexible Ramping Constraint

The CAISO may enforce a Flexible Ramping Constraint in the RTM. Any flexible Dispatch capacity constrained to be available as a result of the Flexible Ramping Constraint in RTM will come from capacity that is not designated to provide Regulation or Operating Reserves, and will not offset the required procurement of those Regulation or Operating Reserves in RTUC. To the extent a resource incurs an opportunity cost for not providing Energy or Ancillary Services in the FMM or RTD interval as a result of a binding Flexible Ramping Constraint, all resources resolving that Flexible Ramping Constraint will be compensated pursuant to Section 11.25. In the FMM or RTD the resources identified as resolving the Flexible Ramping Constraint in the corresponding RTUC run will be the only resources used to resolve the Flexible Ramping Constraint enforced in FMM or RTD. The Flexible Ramping Constraint can be satisfied only by committed online dispatchable Generating Units, Participating Load, and Proxy Demand Response resources with ramping capability for which a Scheduling Coordinator has submitted Economic Bids for Energy for the applicable Trading Hour, and Dynamic System resources as specified below. This constraint cannot be satisfied by System Resources that are not Dynamic System Resources. Dynamic System Resources can become eligible to participate in relieving the Flexible Ramping Constraint if the Scheduling Coordinator scheduling that Resource can demonstrate that it has firm transmission service to the CAISO Balancing Authority Area intertie that allows the resource to deliver additional Energy in Real-Time, consistent with the requirements of Section 1.5 of the Dynamic Scheduling Protocol in Appendix M. This Dynamic System Resource must demonstrate that the Dynamic System Resource has acquired sufficient firm transmission to support the total quantity of Energy and Ancillary Services offered in the Real-Time Market by submitting an E-Tag with a transmission profile that reflects the necessary transmission reservation(s) outside the CAISO Balancing Authority Area.

Procurement of Flexible Ramping Constraint capacity from Dynamic System Resources is limited by the available capacity in Real-Time for the applicable interval on the applicable intertie transmission constraint with which the Dynamic System Resource is associated. The quantity of the flexible ramping capacity for each applicable CAISO Market run will be

determined by CAISO operators using tools that estimate the: 1) expected level of imbalance variability; 2) uncertainty due to forecast error; and 3) differences between the hourly, fifteen (15) minute average and historical five (5) minute Demand levels.

* * *

28.1.2 Availability Of Inter-SC Trades Of Energy

The CAISO allows Inter-SC Trades of Energy at individual PNodes of Generating Units and unique Aggregated Pricing Nodes of Physical Scheduling Plants within the CAISO Balancing Authority Area and at Aggregated Pricing Nodes that are either defined Trading Hubs or Default LAPs. The CAISO does not allow Inter-SC Trades of Energy at Scheduling Points. The CAISO allows submission of Inter-SC Trades of Energy in the DAM and RTM. Inter-SC Trades of Energy submitted for the DAM are settled at the hourly DAM LMP at the applicable Aggregated Pricing Nodes or PNodes. Inter-SC Trades of Energy submitted in the RTM are settled hourly based on the simple average of the four FMM LMPs at the applicable Aggregated Pricing Nodes or PNodes.

28.1.3 Submission Of Inter-SC Trades Of Energy

A Scheduling Coordinator may submit Inter-SC Trades of Energy that it intends to have settled based on DAM LMPs at any time during the Day-Ahead Inter-SC Trade Period and may submit Inter-SC Trades of Energy for a particular hour that it intends to have settled based on the simple average of the four FMM LMPs during that hour at any time during the RTM Inter-SC Trade Period.

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28.1.5 General Validation Rules For Inter-SC Trades

For all Inter-SC Trades of Energy the CAISO shall verify that the Scheduling Coordinators for the Inter-SC Trade of Energy mutually agree on the quantity, location, time period, and CAISO Market (for pricing purposes, i.e., DAM or FMM) for settling the Inter-SC Trade of Energy. Any individual Inter-SC Trade of Energy that is deemed invalid by the CAISO due to inconsistencies between the trading Scheduling Coordinators on these terms will be rejected. The CAISO will

notify trading Scheduling Coordinators within a reasonable time if their Inter-SC Trades of Energy fail these general validation rules as described in the Business Practice Manuals.

28.1.6 Validation Procedures For Physical Trades

All Inter-SC Trades at PNodes and all Inter-SC Trades of Physical Scheduling Plants at their unique Aggregated Pricing Nodes will be subject to validation procedures as specified in this Section. Physical Trades can occur at any individual Generating Unit's PNode or a Physical Scheduling Plant's Aggregated Pricing Node provided the Physical Trade satisfies the CAISO's Physical Trades validation procedures described herein. The Scheduling Coordinators must demonstrate that the trade is supported (directly or through an Inter-SC Trade of Energy with another Scheduling Coordinator) by a Day-Ahead Schedule or FMM Schedule for a Generating Unit or Physical Scheduling Plant at the same location for the Inter-SC Trade of Energy at a level greater than or equal to the amount of the Inter-SC Trade of Energy. The CAISO's validation procedures for Physical Trades include three components: (1) Physical Trade submittal screening, (2) Physical Trade pre-market validation, and (3) Physical Trade post-market confirmation.

* * *

28.1.6.2 Physical Trade Pre-Market Validation

The purpose of the pre-market validation is to determine whether the total MWh quantity of all submitted Physical Trades at a PNode of an individual Generating Unit or the Aggregated Pricing Node of a Physical Scheduling Plant exceeds the resource's Energy Bid MWh. Pre-market validation is performed on all Physical Trades that pass the submittal screening set forth in Section 28.1.6.1. Scheduling Coordinators are notified within a reasonable time of their Physical Trades status as the CAISO conducts the pre-market validation to indicate, at a minimum, whether the Physical Trade is currently "conditionally valid", "conditionally invalid", or "conditionally modified." These Physical Trade notices are preliminary and subject to change until the final pre-market validation at the close of the relevant Inter-SC Trade Period. A Physical Trade with a "conditionally valid" or "conditionally modified" status may be rendered "conditionally invalid" due to the actions of the Scheduling Coordinators to that Physical Trade or by other

trading activities that are linked to the Generating Unit identified for the relevant Physical Trade whenever the quantities specified in the relevant Inter-SC Trades cannot be supported by the underlying Bid. Scheduling Coordinators can use these status notices to make modifications to complete or correct invalid Physical Trades. The CAISO also performs cyclic pre-market validation prior to the close of the relevant Inter-SC Trade Period. Physical Trades that are individually valid are concatenated (daisy chained) with other supporting Physical Trades at the same PNode or Aggregated Pricing Node of the Generating Unit or Physical Scheduling Plant. Once that concatenation is complete, the CAISO will determine whether the concatenated Physical Trades are physically supported by either another Inter-SC Trade of Energy at that same location or the Bid submitted in the relevant CAISO Market on behalf of the resource for that Physical Trade, individually and in the aggregate. If a Physical Trade is not adequately physically supported, the quantities in the Physical Trades of that Scheduling Coordinator and its downstream trading counter-parties are reduced on a pro-rata basis until those Physical Trades are valid. In performing physical pre-market validation of Inter-SC Trades of Energy in the RTM, the CAISO also considers final Inter-SC Trades of Energy for the DAM in determining whether the RTM Physical Trades are physically supported individually or in the aggregate. Specifically, the CAISO determines whether the resource's Bid in the RTM is greater than or equal to the sum of: (1) final Day-Ahead Inter-SC Trades of Energy at that location, (2) the additional Inter-SC Trades of Energy for the RTM at that location and (3) the sum of all upward Day-Ahead Ancillary Services Awards at that location. If the amounts are greater than the resource's submitted Bids in the RTM, the CAISO will adjust down on a prorated basis the RTM Physical Trades. Final Day-Ahead Physical Trades are not adjusted in the RTM pre-market validation. The CAISO does not perform any Settlement on Physical Trade quantities (MWh) that are curtailed during Physical Trade pre-market validation.

28.1.6.3 Physical Trade Post-Market Confirmation

The CAISO conducts post-market confirmation of Physical Trades that pass pre-market validation in Section 28.1.6.2 after the Market Clearing and the market results are posted to ensure that the Generating Unit or Physical Scheduling Plant has a Schedule that can support all of the Physical

Trades. During the post-market confirmation process, the MWh quantity of Physical Trades that passed the CAISO's pre-market validation process may be reduced if the resource supporting the Physical Trades has a Day-Ahead Schedule, HASP Block Intertie Schedule, or HASP Advisory Schedule that is, on average, below the quantity of Physical Trades at that Location. The MWh quantities of Physical Trades that are reduced during the post-market confirmation process are settled at the Existing Zone Generation Trading Hub price for the Existing Zone associated with the resource identified in the Inter-SC Trade of Energy. The portion of Physical Trades that remains intact will be settled at the relevant LMP for the identified PNode for the Generating Unit or Aggregated Pricing Node for the Physical Scheduling Plant.

* * *

28.2.2 Validation

The CAISO's validation of Inter-SC Trades of AS will begin upon submission of an Inter-SC Trade of AS. The CAISO shall conduct a final validation for Inter-SC Trades of AS at the end of the RTM Inter-SC Trade Period. The CAISO will validate each submitted Inter-SC Trade of AS to verify that the contents of the submission match the submittal by the counter-party Scheduling Coordinator by type (Regulation Up, Regulation Down, Spinning Reserve and Non-Spinning Reserve), quantity (MW), and time period. The CAISO will inform the submitting Scheduling Coordinators regarding the validity of a submitted trade of an AS and will allow the Scheduling Coordinator to resubmit the entire Inter-SC Trade of AS if it is not accepted. If only one of the two Scheduling Coordinators successfully submits an Inter-SC Trade of AS, the CAISO will notify both Scheduling Coordinators that the Inter-SC Trade of AS for the specific hour does not match the corresponding Inter-SC Trade of AS. If both Scheduling Coordinators successfully submit the Inter-SC Trade of AS, the CAISO will notify the Scheduling Coordinators that their Inter-SC Trade of AS for the specific hour has been accepted. An Inter-SC Trade of Ancillary Services submitted at a later time, but before the deadline for the submission of the trade for the Trading Hour, renders a previously submitted Inter-SC Trade of AS invalid if it applies to the same hour, same type of AS, and the same Scheduling Coordinators to whom and from whom the AS is traded.

28.2.3 Submission Of Inter-SC Trades Of Ancillary Services

Scheduling Coordinators may submit Inter-SC Trades of Ancillary Services at any time during the RTM Inter-SC Trade Period.

* * *

28.3.2 Validation

The CAISO's validation of Inter-SC Trades of IFM Load Uplift Obligations will begin upon submission of an Inter-SC Trade of IFM Load Uplift Obligation. The CAISO shall conduct a final validation for Inter-SC Trades of IFM Load Uplift Obligations at the end of the RTM Inter-SC Trade Period. The CAISO will validate each submitted Inter-SC Trade of IFM Load Uplift Obligation to verify that the contents of the submission match the submittal by the counter-party Scheduling Coordinator in terms of quantity (MW), and time period. The CAISO will inform the submitting Scheduling Coordinators regarding the validity of a submitted Inter-SC Trade of IFM Load Uplift Obligation and will allow the Scheduling Coordinator to resubmit the entire Inter-SC Trade of IFM Load Uplift Obligation if it is not accepted. If only one of the two Scheduling Coordinators successfully submits an Inter-SC Trade of IFM Load Uplift Obligation, the CAISO will notify both Scheduling Coordinators that the Inter-SC Trade of IFM Load Uplift Obligation for the specific hour does not match the corresponding Inter-SC Trade of IFM Load Uplift Obligation. If both Scheduling Coordinators successfully submit the Inter-SC Trade of IFM Load Uplift Obligation, the CAISO will notify the Scheduling Coordinators that their Inter-SC Trade of IFM Load Uplift Obligations for the specific hour has been accepted. The CAISO will verify that an Inter-SC Trade of IFM Load Uplift Obligation is between different Scheduling Coordinators that are authorized to participate in the CAISO Markets during the time period covered by the trade and that the Trading Hour and the quantity of the trade must be greater than or equal to zero. An Inter-SC Trade of IFM Load Uplift Obligation submitted at a later time renders a previously submitted Inter-SC Trade of IFM Load Uplift Obligation invalid if it applies to the same hour and the same Scheduling Coordinators to whom and from whom the net IFM Load Uplift Obligation is traded.

28.3.3 Submission Of Inter-SC Trades Of IFM Load Uplift Obligation

Scheduling Coordinators may submit Inter-SC Trades of IFM Load Uplift Obligations at any time during the RTM Inter-SC Trade Period.

* * *

30.1.2 Real-Time Market

Economic Bids and Self-Schedules submitted in the RTM apply to a single Trading Hour and are used for all market processes of the RTM. The CAISO will require Scheduling Coordinators to honor their Day-Ahead Ancillary Services Awards when submitting Ancillary Services Bids in the RTM. Bids for Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve service for each Settlement Period must be received at least seventy-five minutes prior to the commencement of that Settlement Period. The Bids shall include information for only the relevant Settlement Period. Failure to provide the information within the stated timeframe shall result in the Bids being declared invalid and rejected by the CAISO.

30.2 Bid Types

There are three types of Bids: Energy Bids (which include Virtual Bids), Ancillary Services Bids, and RUC Availability Bids. Each Bid type can be submitted as either an Economic Bid or a Self-Schedule (except for RUC Availability Bids and Virtual Bids, which cannot be self-scheduled). Economic Bids specify prices for MW amounts of capacity or MWh amounts of Energy. Self-Schedules do not have any prices associated for MW or MWh. Energy Bids, including both Economic Bids and Self-Schedules (where Self-Schedules are otherwise permitted), may be either Supply Bids, Demand Bids, Virtual Supply Bids, or Virtual Demand Bids. Ancillary Services Bids and RUC Availability Bids are Supply Bids only. Ancillary Services may be self-provided by providing a Submission to Self-Provide an Ancillary Service and having that submission accepted by the CAISO. Rules for submitting the three types of Bids vary by the type of resource to which the Bid applies as described in Section 30.5 and as further required in each CAISO Markets process as specified in Sections 31, 33, and 34.

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30.5.1 General Bidding Rules

(a) All Energy and Ancillary Services Bids of each Scheduling Coordinator submitted to the DAM for the following Trading Day shall be submitted at or prior to 10:00 a.m. on the day preceding the Trading Day, but no sooner than seven (7) days prior to the Trading Day. All Energy and Ancillary Services Bids of each Scheduling Coordinator submitted to the RTM for the following Trading Day shall be submitted starting from the time of publication, at 1:00 p.m. on the day preceding the Trading Day, of DAM results for the Trading Day, and ending seventy-five (75) minutes prior to each applicable Trading Hour in the RTM. Scheduling Coordinators may submit only one set of Bids to the RTM for a given Trading Hour, which the CAISO uses for all Real-Time Market processes. The CAISO will not accept any Energy or Ancillary Services Bids for the following Trading Day between 10:00 a.m. on the day preceding the Trading Day and the publication, at 1:00 p.m. on the day preceding the Trading Day, of DAM results for the Trading Day;

(b) Bid prices submitted by a Scheduling Coordinator for Energy accepted and cleared in the IFM and scheduled in the Day-Ahead Schedule may be increased or decreased in the RTM . Bid prices for Energy submitted but not scheduled in the Day-Ahead Schedule may be increased or decreased in the RTM. Incremental Bid prices for Energy associated with Day-Ahead AS or RUC Awards in Bids submitted to the RTM may be revised. Scheduling Coordinators may revise ETC Self-Schedules for Supply in the RTM to the extent such a change is consistent with TRTC Instructions provided to the CAISO by the Participating TO in accordance with Section 16. Scheduling Coordinators may revise TOR Self-Schedules for Supply only in the HASP to the extent such a change is consistent with TRTC Instructions provided to the CAISO by the Non-

Participating TO in accordance with Section 17. Energy associated with awarded Ancillary Services capacity cannot be offered in the Real-Time Market separate and apart from the awarded Ancillary Services capacity;

(c) Scheduling Coordinators may submit Energy, AS and RUC Bids in the DAM that are different for each Trading Hour of the Trading Day;

(d) Bids for Energy or capacity that are submitted to one CAISO Market, but are not accepted in that market are no longer a binding commitment and Scheduling Coordinators may submit Bids in a subsequent CAISO Market at a different price;

(e) The CAISO shall be entitled to take all reasonable measures to verify that Scheduling Coordinators meet the technical and financial criteria set forth in Section 4.5.1 and the accuracy of information submitted to the CAISO pursuant to this Section 30; and

(f) In order to retain the priorities specified in Section 31.4 and 34.12 for scheduled amounts in the Day-Ahead Schedule associated with ETC and TOR Self-Schedules or Self-Schedules associated with Regulatory Must-Take Generation, a Scheduling Coordinator must submit to the Real-Time Market ETC or TOR Self-Schedules, or Self-Schedules associated with Regulatory Must-Take Generation, at or below the Day-Ahead Schedule quantities associated with the scheduled ETC, TOR or Regulatory Must-Take Generation Self-Schedules. If the Scheduling Coordinator fails to submit such Real-Time Market ETC, TOR or Regulatory Must-Take Generation Self-Schedules, the defined scheduling priorities of the ETC, TOR, or Regulatory Must-Take Generation Day-Ahead Schedule quantities may be subject to adjustment in the HASP and the Real-Time Market as further provided in Section 31.4 and 34.12 in order to meet operating conditions.

(g) For Multi-Stage Generating Resources that receive a Day-Ahead Schedule, are awarded a RUC Schedule, or receive an Ancillary Services Award the Scheduling Coordinator must submit an Energy Bid in the Real-Time Market for the same Trading Hour(s). If the Scheduling Coordinator submits an Economic Bid for such Trading Hour(s), the Economic Bid must be for either: the same MSG Configuration scheduled or awarded in the Integrated Forward Market, or the MSG Configuration committed in RUC. If the Scheduling Coordinator submits a Self-Schedule in the Real-Time Market for such Trading Hour(s), then the Energy Self-Schedule may be submitted in any registered MSG Configuration, including the MSG Configuration awarded in the Day-Ahead Market, that can support the awarded Ancillary Services (as further required by Section 8). Scheduling Coordinators for Multi-Stage Generating Resources may submit into the Real-Time Market bids from up to six (6) MSG Configurations in addition to the MSG Configuration scheduled or awarded in the Integrated Forward Market and Residual Unit Commitment, provided that the MSG Transitions between the MSG Configurations bid into the Real-Time Market are feasible and the transition from the previous Trading Hour are also feasible.

(h) For the Trading Hours that Multi-Stage Generating Resources do not have a CAISO Schedule or award from a prior CAISO Market run, the Scheduling Coordinator can submit up to six (6) MSG Configurations into the RTM.

(i) A Scheduling Coordinator cannot submit a Bid to the CAISO Markets for a MSG Configuration into which the Multi-Stage Generating Resource cannot transition due to lack of Bids for the specific Multi-Stage Generating Resource in other MSG Configurations that are required for the requisite MSG Transition.

(j) In order for Multi-Stage Generating Resource to meet any Resource Adequacy must-offer obligations, the responsible Scheduling Coordinator must submit either an Economic Bid or Self-Schedule for at least one MSG Configuration into the Day-Ahead Market and Real-Time Market that is capable of fulfilling that Resource Adequacy obligation, as feasible. The Economic Bid shall cover the entire capacity range between the maximum bid-in Energy MW and the higher of Self-Scheduled Energy MW and the Multi-Stage Generating Resource plant-level PMin.

(k) For any given Trading Hour, a Scheduling Coordinator may submit Self-Schedules and/or Submissions to Self-Provide Ancillary Services in only one MSG Configuration for each Generating Unit or Dynamic Resource-Specific System Resource.

(l) In any given Trading Hour in which a Scheduling Coordinator has submitted a Self-Schedule for a Multi-Stage Generating Resource, the Scheduling Coordinator may also submit Bids for other MSG Configurations provided that they concurrently submit Bids that enable the applicable CAISO Market to transition the Multi-Stage Generating Resource to other MSG Configurations.

(m) If in any given Trading Hour the Multi-Stage Generating Resource was awarded Regulation or Operating Reserves in the IFM, any Self-Schedules or Submissions to Self-Provide Ancillary Services the Scheduling Coordinator submits for that Multi-Stage Generating Resource in the RTM must be for the same MSG Configuration for which Regulation or Operating Reserve is Awarded in IFM for that Multi-Stage Generating Resource in that given Trading Hour.

(n) If a Multi-Stage Generating Resource has received a binding RUC Start-Up Instruction as provided in Section 31, any Self-Schedule or

Submission to Self-Provide Ancillary Services in the RTM must be in the same MSG Configuration committed in RUC.

(o) If in any given Trading Hour the Multi-Stage Generating Resource is scheduled for Energy in the IFM, any Self-Schedules the Scheduling Coordinator submits for that Multi-Stage Generating Resource in the RTM must be for the same MSG Configuration for which Energy is scheduled in IFM for that Multi-Stage Generating Resource in that given Trading Hour.

(p) For a Multi-Stage Generating Resource, the Bid(s) submitted for the resource's configuration(s) shall collectively cover the entire capacity range between the maximum bid-in Energy MW and the higher of the Self-Scheduled Energy MW and the Multi-Stage Generating Resource plant-level PMin. This rule shall apply separately to the Day-Ahead Market and the Real-Time Market.

(q) A Scheduling Coordinator may submit a Self-Schedule Hourly Block for the RTM as an import to or an export from the CAISO Balancing Authority Area and may also submit Self-Scheduled Hourly Blocks for Ancillary Services imports. Such a Bid shall be for the same MWh quantity for each of the four fifteen (15)-minute intervals that make up the applicable Trading Hour.

(r) A Scheduling Coordinator may submit a Variable Energy Resource Self-Schedule for the RTM can be submitted from a Variable Energy Resource. A Scheduling Coordinator can use either the CAISO forecast for Expected Energy in the RTM or can provide its own forecast for Expected Energy pursuant to the requirements specified in Section 4.8.2. The Scheduling Coordinator must indicate in the Master File whether it is using its own forecast or the CAISO forecast for its resource in support of the Variable Energy Self-Schedule. The Scheduling Coordinator is not

required to include the same MWh quantity for each of the four fifteen (15)-minute intervals that make up the applicable Trading Hour for the Variable Energy Resource Self-Schedule include. If an external Variable Energy Resource that is not using a forecast of its output provided by the CAISO submits a Variable Energy Resource Self-Schedule and the Expected Energy is not delivered in the FMM, the Scheduling Coordinator for the Variable Energy Resource will be subject to the Decline Potential Charge as described in Section 11.31. Scheduling Coordinators for Dynamically Scheduled Variable Energy Resources that provide the CAISO with a two-hour rolling forecast with five-minute granularity can submit Variable Energy Resource Self-Schedules.

(s) Scheduling Coordinators can submit Economic Hourly Block Bids to be considered in the HASP and to be accepted as binding Schedules with the same MWh award for each of the four FMM intervals. Scheduling Coordinator can also submit Economic Hourly Block Bids for Ancillary Services. As specified in Section 11, a cleared Economic Hourly Block Bid is not eligible for Bid Cost Recovery.

(t) Scheduling Coordinators can submit Economic Hourly Block Bids with Intra-Hour Option. If accepted in the HASP, such a Bid creates a bindingschedule with same MWh awards for each of the four FMM intervals. After that, the RTM can optimize such schedules for economic reasons once through an FMM during the Trading Hour. As specified in Section 11, a cleared Economic Hourly Block Bid with Intra-Hour Option is not eligible for Bid Cost Recovery.

(u) A Scheduling Coordinator submitting Bids to the RTM is not required to submit a Self-Schedule Hourly Block, a Variable Energy Resource Self-Schedule, an Economic Hourly Block Bid, or an Economic Hourly Block

Bid with Intra-Hour Option, and may instead choose to participate in the RTM through Economic Bids or Self-Schedules.

30.5.2 Supply Bids

30.5.2.1 Common Elements for Supply Bids

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

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

Scheduling Coordinators submitting Bids for Scheduling Points must adhere to the e-Tagging requirements outlined in Section 30.6.2.

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30.5.2.4 Supply Bids for System Resources

In addition to the common elements listed in Section 30.5.2.1, Supply Bids for System Resources shall also contain: the relevant Ramp Rate; Start-Up Costs; and Minimum Load Costs. Resource-Specific System Resources may elect the Proxy Cost option or Registered Cost option for Start-Up Costs and Minimum Load Costs as provided in Section 30.4. Other System Resources are not eligible to recover Start-Up Costs and Minimum Load Costs. Resource-Specific System Resources are eligible to participate in the Day-Ahead Market on an equivalent basis as Generating Units and are not obligated to participate in RUC or the RTM if the resource did not receive a Day-Ahead Schedule unless the resource is a Resource Adequacy Resource. If

the Resource-Specific System Resource is a Resource Adequacy Resource, the Scheduling Coordinator for the resource is obligated to make it available to the CAISO Market as prescribed by Section 40.6. Dynamic Resource-Specific System Resources are also eligible to participate in the HASP and RTM on an equivalent basis as Generating Units. The quantity (in MWh) of Energy categorized as Interruptible Imports (non-firm imports) can only be submitted through Self-Schedules in the Day-Ahead Market and cannot be incrementally increased in the HASP or RTM. Bids submitted to the Day-Ahead Market for ELS Resources will be applicable for two days after they have been submitted and cannot be changed the day after they have been submitted.

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30.5.2.5 Supply Bids for Metered Subsystems

Consistent with the bidding rules specified in this Section 30.5, Scheduling Coordinators that represent MSS Operators may submit Bids for Energy and Ancillary Services, including Self-Schedules and Submissions to Self-Provide an Ancillary Service, to the DAM. All Bids to supply Energy by MSS Operators must identify each Generating Unit on an individual unit basis. The CAISO will not accept aggregated Generation Bids without complying with the requirements of Section 4.9.12 of the CAISO Tariff. All Scheduling Coordinators that represent MSS Operators must submit Demand Bids at the relevant MSS LAP. Scheduling Coordinators that represent MSS Operators must comply with Section 4.9 of the CAISO Tariff. Scheduling Coordinators that represent MSS Operators that have opted out of RUC participation pursuant to Section 31.5 must Self-Schedule one hundred percent (100%) of the Demand Forecast for the MSS. For an MSS that elects Load following, the MSS Operator shall also self-schedule or bid Supply to match the Demand Forecast. All Bids for MSSs must be identify each Generating Unit on an individual unit basis or a System Unit. For an MSS that elects Load following consistent with Section 4.9.13.2, the Scheduling Coordinator for the MSS Operator must include the following additional information with its Bids: the Generating Unit(s) that are Load following; the range of the Generating Unit(s) being reserved for Load following; whether the quantity of Load following capacity is either up or down; and, if there are multiple Generating Units in the MSS, the priority list or distribution factors among the Generating Units. The CAISO will not dispatch the resource

within the range declared as Load following capacity, leaving that capacity entirely available for the MSS to dispatch. The CAISO uses this information in the IFM runs and the RUC to simulate MSS Load following. The Scheduling Coordinator for the MSS Operator may change these characteristics through the Bid submission process in the RTM.

If the Load following resource is also an RMR Unit, the MSS Operator must not specify the Maximum Net Dependable Capacity specified in the RMR Contract as Load following up or down capacity to allow the CAISO to access such capacity for RMR Dispatch.

30.5.2.6 Ancillary Services Bids

There are four distinct Ancillary Services: Regulation Up, Regulation Down, Spinning Reserve and Non-Spinning Reserve. A resource shall be eligible to provide Ancillary Service if it has complied with the CAISO's certification and testing requirements as contained in Appendix K and the CAISO's Operating Procedures. Scheduling Coordinators may use Dynamic System Resources to Self-Provide Ancillary Services as specified in Section 8. All System Resources, including Dynamic System Resources and Non-Dynamic System Resources, will be charged the Shadow Price as prescribed in Section 11.10, for any awarded Ancillary Services. A Scheduling Coordinator may submit Ancillary Services Bids for Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve for the same capacity by providing a separate price in $/MW per hour as desired for each Ancillary Service. The Bid for each Ancillary Services is a single Bid segment. Only resources certified by the CAISO as capable of providing Ancillary Services are eligible to provide Ancillary Services and submit Ancillary Services Bids. In addition to the common elements listed in Section 30.5.2.1, all Ancillary Services Bid components of a Supply Bid must contain the following: (1) the type of Ancillary Service for which a Bid is being submitted; (2) Ramp Rate (Operating Reserve Ramp Rate and Regulation Ramp Rate, if applicable); and (3) Distribution Curve for Physical Scheduling Plant or System Unit. A Scheduling Coordinator may only submit an Ancillary Services Bid or Submission to Self-Provide an Ancillary Service for Multi-Stage Generating Resources for the Ancillary Service for which the specific MSG Configurations are certified. For any such certified MSG Configurations the Scheduling Coordinator may submit only one Operating Reserve Ramp Rate and Regulation Ramp Rate. An Ancillary Services Bid

submitted to the Day-Ahead Market when submitted to the Day-Ahead Market may be, but is not required to be, accompanied by an Energy Bid that covers the capacity offered for the Ancillary Service. Submissions to Self-Provide an Ancillary Services submitted to the Day-Ahead Market when submitted to the Day-Ahead Market may be, but are not required to be, accompanied by an Energy Bid that covers the capacity to be self-provided. If a Scheduling Coordinator's Submission to Self-Provide an Ancillary Service is qualified as specified in Section 8.6, the Scheduling Coordinator must submit an Energy Bid that covers the self-provided capacity prior to the close of the Real-Time Market for the day immediately following the Day-Ahead Market in which the Ancillary Service Bid was submitted. Except as provided below, the Self-Schedule for Energy need not include a Self-Schedule for Energy from the resource that will be self-providing the Ancillary Service. If a Scheduling Coordinator is self-providing an Ancillary Service from a Fast Start Unit, no Self-Schedule for Energy for that resource is required. If a Scheduling Coordinator proposes to self-provide Spinning Reserve, the Scheduling Coordinator is obligated to submit a Self-Schedule for Energy for that particular resource, unless as discussed above the particular resource is a Fast Start Unit. When submitting Ancillary Service Bids in the Real-Time Market, Scheduling Coordinators for resources that either have been awarded or self-provide Spinning Reserve or Non-Spinning Reserve capacity in the Day-Ahead Market must submit an Energy Bid for at least the awarded or self-provided Spinning Reserve or Non-Spinning Reserve capacity, otherwise the CAISO will apply the Bid validation rules described in Section 30.7.6.1. As provided in Section 30.5.2.6.4, a Submission to Self-Provide an Ancillary Service shall contain all of the requirements of a Bid for Ancillary Services with the exception of Ancillary Service Bid price information. In addition, Scheduling Coordinators must comply with the Ancillary Services requirements of Section 8. Scheduling Coordinators submitting Self-Schedule Hourly Blocks for Ancillary Services Bids for the Real-Time Market must also submit an Energy Bid for the associated Ancillary Services Bid under the same Resource ID, otherwise the bid validation rules in Section 30.7.6.1 will apply to cover any portion of the Ancillary Services Bid not accompanied by an Energy Bid. As described in Section 34.2.3, if the resource submits a Self-Scheduled Hourly Block, the CAISO will only use the Ancillary Services Bid in the RTM optimization and will

not use the associated Energy Bid for the same Resource ID to schedule Energy from the Non-Dynamic System Resource in the RTM. Scheduling Coordinators must also comply with the bidding rules associated with the must offer requirements for Ancillary Services specified in Section 40.6.

* * *

30.5.4 Wheeling Through Transactions

A Wheeling Through transaction consists of an Export Bid and an Import Bid with the same Wheeling reference (a unique identifier for each Wheeling Through transaction). If the Wheeling reference does not match at the time the relevant market closes, the Wheeling Through transaction will be erased; this includes any Economic Bid or Self-Schedule for the resource for that Trading Hour. Wheeling Through transactions with matching Wheeling references will be kept balanced in the IFM and RTM; that is, to the extent an Export Bid or Import Economic Bid or Self-Schedule specify different quantities, only that matching quantity will clear the CAISO Markets.

* * *

30.6.2 E-Tag Rules and Treatment of Intertie Schedules

In addition to complying with all generally applicable E-Tagging requirements, Scheduling Coordinators must submit their E-tags consistent with the requirements specified in this Section 30.6.2. If a Scheduling Coordinator receives an intra-hour Schedule change, then the Scheduling Coordinator must, by twenty minutes before the start of the FMM interval to which the Schedule change applies, ensure that an updated energy profile reflects the change. Absent extenuating circumstances, the CAISO automatically updates Energy profiles on E-tags for Energy Schedules that change from HASP to the FMM within a Trading Hour. In performing this service for a Scheduling Coordinator, the CAISO does not assume any responsibility for compliance with any E-tag requirements or obligations to which the Scheduling Coordinator is subject. The changed energy profile will apply for the balance of the operating hour unless it is subsequently changed by a further updated energy profile.

30.6.2.1 Self-Scheduled Hourly Blocks

By twenty minutes prior to the applicable Trading Hour, the Scheduling Coordinator must submit an E-Tag in support of Self-Scheduled Hourly Blocks. The transmission profile must be greater than or equal to the Energy profile, and the Energy profile must equal the Self-Scheduled Hourly Block. The CAISO may modify the Energy profile due to Reliability related curtailments.

30.6.2.2 Variable Energy Resource Self-Schedule

By twenty minutes prior to the applicable Trading Hour, the Scheduling Coordinator must submit an E-Tag in support of a Variable Energy Resource Self-Schedule. The transmission profile must be greater than or equal to the Energy profile, and the Energy profile must equal the Variable Energy Resource Self-Schedule. The CAISO may modify the Energy profile due to Reliability related curtailments.

30.6.2.3 Economic Hourly Block Bid

By twenty minutes prior to the applicable Trading Hour, the Scheduling Coordinator must submit an E-Tag in support of an Economic Hourly Block Bid. The transmission profile must be greater than or equal to the Energy profile, and the Energy profile must equal the Economic Hourly Block Bid as awarded through HASP. The CAISO may modify the Energy profile due to Reliability related curtailments.

30.6.2.4 Economic Hourly Block Bid with Intra-Hour Option

By twenty minutes prior to the applicable Trading Hour, the Scheduling Coordinator must submit an E-Tag in support of an Economic Hourly Block Bid. The transmission profile must be greater than or equal to the Energy profile, and the Energy profile must equal the Economic Hourly Block Bid as awarded through HASP. The CAISO may modify the Energy profile due to Reliability related curtailments. In the case of an intra-hour redispatch from the FMM, the CAISO may increment or decrement the Energy profile to correspond to the intra-hour redispatch.

30.6.2.5 FMM Economic Bid

By twenty minutes prior to the applicable Trading Hour, the Scheduling Coordinator must submit an E-Tag in support of a FMM Economic Bid. The transmission profile must be greater than or equal to the maximum bid-in capacity for the Trading Hour, and the Energy profile must equal the MWs awarded for the first FMM interval of the Operating Hour. If the Scheduling Coordinator

intends to limit its participation in the FMM to the quantity in the HASP advisory energy schedule (including zero), the Scheduling Coordinator may update its transmission profile to the maximum amount it wants to make available to the FMM prior to the start of the binding FMM optimization, which is no earlier than thirty-seven and a half minutes before the applicable Trading Hour. If the Scheduling Coordinator does not have a transmission profile greater than or equal to its advisory Energy schedule, then the CAISO will limit the schedule for Energy in the FMM so that it does not exceed amounts greater than what is listed in the transmission profile. Cleared FMM Economic Bids are eligible for Bid Cost Recovery as specified in Section 11.8.

* * *

30.7.1 Scheduling Coordinator Access

Each Scheduling Coordinator will be provided access to the CAISO's secure communication system to submit, modify and cancel Bids prior to the close of both the DAM and RTM, as specified in Section 30.5.1. The CAISO shall provide information regarding submitted Bids including, but not be limited to, the following: (i) notification of acceptance; (ii) notification of validation; (iii) notification of rejection; (iv) notification of status; (v) notification of submission error(s); and (vi) default modification or generation of Bids as further provided below, if any, on behalf of Scheduling Coordinators.

30.7.3.6.3 Position Limits

For each Convergence Bidding Entity, the CAISO will reject all Virtual Bids submitted by its Scheduling Coordinator at any Eligible PNode, Eligible Aggregated PNode (other than a Default LAP or Trading Hub), or Intertie that exceed the position limits specified in this Section 30.7.3.6.3. If the Scheduling Coordinator uses multiple SCIDs on behalf of a Convergence Bidding Entity, the position limits will apply to the sum of those Virtual Bids submitted at the Eligible PNode, Eligible Aggregated PNode (other than a Default LAP or Trading Hub), or Intertie. The CAISO will perform all position limit calculations based on the highest Virtual Bid segment MW point submitted in the Virtual Bid Curve. The CAISO will not net Virtual Supply Bids and Virtual Demand Bids in performing the position limit calculations. The affected Scheduling Coordinator will be provided notice that position limits have been violated. If the Scheduling Coordinator does not resubmit

Virtual Bids within the position limits, the CAISO will reject Virtual Bids for all hours at each Eligible PNode, Eligible Aggregated PNode (other than a Default LAP or Trading Hub), and Intertie where the position limits are violated. Position limits only apply to Eligible PNodes or Eligible Aggregated PNodes (other than Default LAPs or Trading Hubs), and Interties.

* * *

30.7.3.6.3.2 Position Limits at Interties

For an Intertie, the locational limits will be equal to a percentage of the Operating Transfer Capability of the Intertie. The percentages used to calculate the position limits of each Convergence Bidding Entity at Interties will be the following percentages of the published locational limits**:**

(a) Position limits of zero (0) percent will apply during the time period beginning as of the effective date of this tariff provision through the last day of the twelfth month following the effective date of this section 30.7.3.6.3.2.

(b) Position limits of five (5) percent will apply during the time period beginning as of the first day of the thirteenth month following the effective date of this tariff provision through the last day of the twentieth month following the effective date of this tariff provision.

(c) Position limits of twenty-five (25) percent will apply during the time period beginning on the first day of the twenty-first month following the effective date of this tariff provision through the last day of the twenty-fourth month following the effective date of this tariff provision.

(d) Position limits of fifty (50) percent will apply during the time period beginning on the first day of the twenty-fifth month following the effective date of this tariff provision through the last day of the twenty-eighth month following the effective date of this tariff provision.

(e) Position limits will cease to apply beginning on the first day of the twenty-ninth month following the effective date of this tariff provision.

The CAISO will enforce the locational limits for Interties at Bid submission and at Market Close for Virtual Bids. The CAISO will utilize the 9:00 AM Operating Transfer Capability for Bids submitted after 9:00 AM until the close of the Day-Ahead Market for the next Trading Day.

* * *

30.7.4 RTM Validation

RTM Bids will include the same validation process implemented in the DAM except that the CAISO will not validate the Bid before and again after the Master File Data update. RTM Bids are only validated based on the current Master File Data on the relevant Trading Day.

* * *

30.7.6 Validation And Treatment Of Ancillary Services Bids

30.7.6.1 Validation of Ancillary Services Bids

Throughout the validation process described in Section 30.7, the CAISO will verify that each Ancillary Services Bid conforms to the content, format and syntax specified for the relevant Ancillary Service. If the Ancillary Services Bid does not so conform, the CAISO will send a notification to the Scheduling Coordinator notifying the Scheduling Coordinator of the errors in the Bids as described in Section 30.7. When the Bids are submitted, a technical validation will be performed to verify that the bid quantity of Regulation, Spinning Reserve, or Non-Spinning Reserve does not exceed the certified Ancillary Services capacity for Regulation, or Operating Reserves on the Generating Units, System Units, Participating Loads, Proxy Demand Resources, and external imports/exports bid. The Scheduling Coordinator will be notified within a reasonable time of any validation errors. For each error detected, an error message will be generated by the CAISO in the Scheduling Coordinator's notification screen, which will specify the nature of the error. The Scheduling Coordinator can then look at the notification messages to review the detailed list of errors, make changes, and resubmit if it is still within the CAISO's timing requirements. The Scheduling Coordinator is also notified of successful validation. If a resource is awarded or has qualified Self-Provided Ancillary Services in the Day-Ahead Market, the following rules will apply: (1): if no Energy Self-Schedule is submitted to support a Submission to Self-Provide an Ancillary Service for Regulation, the Submission to Self-Provide

an Ancillary Service will be invalidated: (2) if no Energy Supply Bid is submitted to cover the awarded or Self- Provided Ancillary Services for Spinning Reserve or Non-Spinning Reserve by the Market Close of the RTM, the CAISO will generate or extend an Energy Supply Bid as necessary to cover the awarded or Self-Provided Ancillary Services capacity using the registered values in the Master File and relevant fuel prices as described in the Business Practice Manuals for use in the RTM and IFM. If an AS Bid or Submission to Self-Provide an AS is submitted in the Real-Time Market for Spinning Reserve or Non-Spinning Reserve without an accompanying Energy Supply Bid at all, the AS Bid or Submission to Self-Provide an Ancillary Service will be erased. If an AS Bid is submitted in the Real-Time Market for Spinning Reserve and Non-Spinning Reserve with only a partial Energy Supply Bid for the AS capacity, the CAISO will generate an Energy Supply Bid for the uncovered portions. If a Submission to Self-Provide an Ancillary Service is submitted in the Real-Time Market for Spinning Reserve and Non-Spinning Reserve with only a partial Energy Supply Bid for the AS capacity bid in, the CAISO will not generate or extend an Energy Supply Bid for the uncovered portions. For Generating Units with certified Regulation capacity, if there no Bid for Regulation in the Real-Time Market, but there is a Day-Ahead award for Regulation Up or Regulation Down or a submission to self-provide Regulation Up or Regulation Down, respectively, the CAISO will generate a Regulation Up or Regulation Down Bid at the default Ancillary Service Bid price of $0 up to the certified Regulation capacity for the Generating Unit minus any Regulation awarded or self-provided in the Day- Ahead. If there is a Bid for Regulation Up or Regulation Down in the Real-Time Market, the CAISO will increase the respective Bid up to the certified Regulation capacity for the Generating Unit minus any Regulation awarded or self-provided in the Day-Ahead. If a Self-Schedule amount is greater than the Regulation Limit for Regulation Up, the Regulation Up Bid will be erased.

Notwithstanding any of the provisions of Section 30.7.6.1 set forth above, the CAISO will not insert or extend any Bid for Regulation Up or Regulation Down for a Use-Limited Resource of a Load Following MSS Operator. The CAISO will not insert a Spinning Reserve and Non-Spinning Reserve Ancillary Service Bid at $0 in the Real-Time Market for any certified

Operating Reserve capacity of a resource unless that resource submits an Energy Supply Bid but fails to submit an Ancillary Service Bid in the Real-Time Market.

30.7.6.2 Treatment of Ancillary Services Bids

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

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

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

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

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

(d) evaluate Import Bids along with Bids from internal resources (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area);

(e) establish Real-Time Ancillary Service Awards through the FMM from imports and resources internal to the CAISO Balancing Authority Area (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area) at fifteen (15) minutes intervals to the hour of operation; and

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

30.8 Bids On Out-Of-Service Paths At Scheduling Points Prohibited

Scheduling Coordinators shall not submit any Bids, including Virtual Bids, or ETC Self-Schedules at Scheduling Points using a transmission path for any Settlement Period for which the Total Transfer Capability for that path is zero (0) MW. The CAISO shall reject Bids or ETC Self-Schedules submitted at Scheduling Points where the Total Transfer Capability on the transmission path is zero (0) MW. If the Total Transfer Capability of a transmission path at the relevant Scheduling Point is reduced to zero (0) after Day-Ahead Schedules have been issued, then, if time permits, the CAISO shall direct the responsible Scheduling Coordinators to reduce all MWh associated with the Bids on such zero-rated transmission paths to zero (0) in the RTM. As necessary to comply with Applicable Reliability Criteria, the CAISO shall reduce any non-zero (0) RTM Bids across zero-rated transmission paths to zero after the Market Close for the RTM.

30.9 Virtual Bids

Virtual Bids are Energy Bids that may be submitted only in the Day-Ahead Market, at Eligible PNodes, including PNodes located at an Intertie where virtual bidding is permitted, or Eligible Aggregated PNodes, including Aggregated PNodes located at an Intertie, where virtual bidding is

permitted, by Scheduling Coordinators representing Convergence Bidding Entities. Virtual Bids are either Virtual Supply Bids or Virtual Demand Bids. A Virtual Bid submitted in the Day-Ahead Market and cleared in the IFM represents a commitment to liquidate a Day-Ahead award in the Real-Time Market at the price determined for the applicable Eligible PNode or Eligible Aggregated PNode as set forth in Section 11.3. For each SCID associated with a Convergence Bidding Entity, there may be only one Virtual Supply Bid and one Virtual Demand Bid per each Eligible PNode or Eligible Aggregated PNode in the Day-Ahead Market. The minimum size of a segment of a Virtual Bid is one (1) MW.

* * *

31.3.1.1 Integrated Forward Market Output

The IFM produces: (1) a set of hourly Day-Ahead Schedules, AS Awards, and AS Schedules for all participating Scheduling Coordinators that cover each Trading Hour of the next Trading Day; and (2) the hourly LMPs for Energy and the ASMPs for Ancillary Services to be used for settlement of the IFM. For a Multi-Stage Generating Resource, the IFM produces a Day-Ahead Schedule for no more than one MSG Configuration per Trading Hour. In addition, the IFM will produce the MSG Transition and the MSG Configuration indicators for the Multi-Stage Generating Resource, which would establish the expected MSG Configuration in which the Multi-Stage Generating Resource will operate. During a transition, the committed MSG Configuration is considered to be the “from” MSG Configuration. The CAISO will publish the LMPs at each PNode as calculated in the IFM. In determining Day-Ahead Schedules, AS Awards, and AS Schedules the IFM optimization will minimize total Bid Costs based on submitted and mitigated Bids while respecting the operating characteristics of resources, the operating limits of transmission facilities, and a set of scheduling priorities that are described in Section 31.4. In performing its optimization, the IFM first tries to complete its required functions utilizing Effective Economic Bids without adjusting Self-Schedules, and skips Ineffective Economic Bids and adjusts Self-Schedules only if it is not possible to balance Supply and Demand and manage Congestion in an operationally prudent manner with available Effective Economic Bids. The process and criteria by which the IFM adjusts Self-Schedules and other Non-priced Quantities are

described in Sections 27.4.3, 31.3.1.3 and 31.4. The Day-Ahead Schedules are binding commitments, including the commitment to Start-Up, if necessary, to comply with the Day-Ahead Schedules. The CAISO will not issue separate Start-Up Instructions for Day-Ahead commitments. A resource's status, however, can be modified as a result of additional market processes occurring in the RTM.

* * *

31.5.3 RUC Procurement Target

The procurement target for RUC in any given Trading Hour will be determined based on the next day's hourly CAISO Forecast Of CAISO Demand less the Energy scheduled in the Day-Ahead Schedule, and accounting for other factors, as appropriate, such as Demand Forecast error and estimated incremental RTM Bids including those from Participating Intermittent Resources. The adjustments listed in Sections 31.5.3.1 to 31.5.3.6 will be made to the CAISO Forecast Of CAISO Demand to account for the conditions as provided therein. Adjustments may be made on a RUC Zone basis to ensure that RUC results in adequate local capacity procurement. The RUC procurement target-setting procedure is designed to meet the requirements of reliable grid operation without unnecessary over-procurement of RUC Capacity or over-commitment of resources. Additional detail on the process for setting the RUC procurement target is specified in the Business Practice Manuals.

* * *

31.5.3.5 Real-Time Expected Incremental Supply Self-Schedule Adjustment

In order to avoid over procurement of RUC, the CAISO shall, using a similar-day approach, estimate the RTM Self-Schedules for resources that usually submit RTM Self-Schedules that are greater than their Day-Ahead Schedules. The CAISO Operator may set the length of the Self-Schedule moving average window. Initially this moving average window shall be set by default to seven (7) days; in which case the weekday estimate is based on the average of five (5) most recent weekdays and the weekend estimate is based on the average of the two (2) most recent weekend days. To the extent weather conditions differ significantly from the historical days, additional adjustment may be necessary. After determining the estimate of Real-Time Self-

Schedules, using a similar day forecasting approach, the CAISO adjusts the CAISO Forecast Of CAISO Demand of a RUC Zone based on the forecasted quantity changes in Supply as a result of Self-Schedules submitted in the RTM. This adjustment for forecasted Real-Time Self-Schedules may result in positive or negative adjustments. Demand adjustments to the CAISO Forecast Of CAISO Demand result when there is a net forecast decrease in Real-Time Self-Schedule Supply relative to the Day-Ahead Schedule Supply. Supply adjustments to the individual resources occur when there is a net forecast increase in Real-Time Self-Schedule Supply relative to the Day-Ahead Schedule Supply of the individual resource.

* * *

31.6.3 Conditions Permitting CAISO To Abort Day-Ahead Market

If, despite the variation of any time requirement or the omission of any step, the CAISO either fails to receive sufficient Bids or fails to clear the Day-Ahead Market, the CAISO may abort the Day-Ahead Market and require all Bids to be submitted in the RTM

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31.8 Constraints Enforced at Intertie Scheduling Points

Within the IFM optimization, the CAISO enforces a constraint at each Intertie Scheduling Point such that Physical and virtual imports net of physical and virtual exports must be less than or equal to the scheduling limit at the Scheduling Point in the applicable direction. The CAISO incorporates the Shadow Price of this IFM constraint into the CAISO Market runs used to establish LMPs for both physical and virtual awards. Within the RUC process, the CAISO enforces a constraint at each Intertie Scheduling Point such that physical imports net of physical exports must be less than or equal to the scheduling limit at the Scheduling Point in the applicable direction. Through this RUC constraint the CAISO determines what Day-Ahead Schedules can have an E-Tag submitted Day-Ahead. Day-Ahead Schedules precluded from submitting an E-Tag in the Day-Ahead on this basis are exempt from the charges described in Section 11.32.

* * *

33 [Not Used]

33.1 [Not Used]

33.2 [Not Used]

33.3 [Not Used]

33.4 [Not Used]

33.5 [NOT USED]

33.6 [Not Used]

33.7 [Not Used]

33.8 [Not Used]

33.9 [Not Used]

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34. Real-Time Market

The CAISO conducts the Real-Time Market on any given Operating Day in which Scheduling Coordinators may submit Bids, and the CAISO commits and Dispatches Energy and procures Energy and Ancillary Services. The Real-Time Market consists of the following processes: (1) the Hour-Ahead Scheduling Process, (2) Real-Time Unit Commitment (RTUC), (3) the Short-Term Unit Commitment (STUC), (4) the Fifteen Minute Market (FMM), and (5) the Real-Time Dispatch (RTD).

The CAISO shall dispatch all resources, including Participating Load and Proxy Demand Resource, pursuant to submitted Bids or pursuant to the provisions below on Exceptional Dispatch.

34.1 Inputs To The Real-Time Market

The CAISO utilizes the following data and information as inputs in conducting the Real-Time Market:

34.1.1 Day-Ahead Market Results as Inputs to the Real-Time Market

All of the Real-Time Market processes utilize results produced by the Day-Ahead Market for each Trading Hour of the Trading Day, including the combined commitments contained in the Day-Ahead Schedules, Day-Ahead Ancillary Services Awards, and RUC Awards. Although the RTM utilizes such results as an input to the RTM and the transactions associated with those DAM

results are settled based on the relevant DAM prices, such transactions are not deemed performed until the Real-Time.

34.1.2 Market Model and System Information

The CAISO utilizes the Base Market Model used in the Day-Ahead Market and adjusted as described in 27.5.1 and 27.5.6, and other system information provided through the State Estimator output, resource outage and derate/rerate information in conducting all of the Real-Time Market processes. Updates to the Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 used in all of the Real-Time Market processes include current estimates of real-time unscheduled flow at the Interties. The CAISO utilizes the most up-to-date Base Market Model and system information throughout the Real-Time Market processes to the extent feasible.

34.1.3 Bids in The Real-Time Market

Scheduling Coordinators may submit Bids, including Self-Schedules, for Supply that the CAISO shall use for the Real-Time Market, starting from the time Day-Ahead Schedules are posted, which is approximately 1:00 p.m., unless the posting of the Day-Ahead Market results are delayed for reasons specified in Section 31.6, until seventy-five (75) minutes prior to each applicable Trading Hour in the Real-Time. Scheduling Coordinators can submit Bids in the form of: (1) an Economic Bid for a Schedule in the RTM; (2) a Self-Schedule for acceptance to the RTM; (3) a Self-Schedule Hourly Block for acceptance in the HASP; (4) a Variable Energy Resource Self-Schedule for the RTM; (5) an Economic Hourly Block Bid for acceptance in the HASP; or (6) an Economic Hourly Block Bid with Intra-Hour Option for acceptance in the HASP and the FMM. This includes Self-Schedules by Participating Load that is modeled using the Pumped-Storage Hydro Unit. Scheduling Coordinators may not submit Bids, including Self-Schedules, for CAISO Demand in the RTM. Scheduling Coordinators may submit Bids, including Self-Schedules, for exports at Scheduling Points in the RTM. The rules for submitted Bids specified in Section 30 apply to Bids submitted to the RTM. Scheduling Coordinators may not submit Virtual Bids to the Real-Time Market, although Virtual Awards from the DAM are settled for their liquidated positions based on prices from the FMM. In the case of Multi-Stage Generating Resources, the RTM procedures will optimize Transition Costs in addition to the Start-

Up and Minimum Load Costs. If a Scheduling Coordinator submits a Self-Schedule or a Submission to Self-Provide Ancillary Services for a given MSG Configuration in a given Trading Hour, all of the RTM processes will consider the Start-Up Cost, Minimum Load Cost, and Transition Cost associated with any Economic Bids for other MSG Configurations as incremental costs between the other MSG Configurations and the self-scheduled MSG Configuration. In such cases, incremental costs are the additional costs incurred to transition or operate in an MSG Configuration in addition to the costs associated with the self-scheduled MSG Configuration.

34.1.4 Real-Time Validation of Schedules and Bids

After the Market Close of the Real-Time Market, the CAISO performs a validation process consistent with the provisions set forth in Section 30.7 and the following additional rules. The CAISO will insert a Generated Bid to cover any RUC Award or Day-Ahead Schedule in the absence of any Self-Schedule or Economic Bid components, or to fill in any gaps between any Self-Schedule Bid and any Economic Bid components to cover a RUC Award or Day-Ahead Schedule for use in the RTM. Schedules and Bids submitted to the RTM to supply Energy and Ancillary Services will be considered in the various RTM processes, including the MPM process, the HASP, the STUC, the RTUC, the FMM and the RTD.

34.1.5 Mitigating the Bid Sets Used in the RTM Optimization Processes

After the Market Close of the RTM, after the CAISO has validated the Bids pursuant to Section 30.7 and Section 34.1.4, and prior to conducting any other RTM processes, the CAISO conducts a MPM process. The results are used in the RTM optimization processes. Bids on behalf of Demand Response Resources, Participating Load, and Non-Generator Resources are considered in the MPM process but are not subject to Bid mitigation. The MPM process produces results for each fifteen (15) minute interval of the Trading Hour and thus may produce up to four mitigated Bids for any given resource for the Trading Hour. The determination as to whether a Bid is mitigated is made based on the non-competitive Congestion component of each LMP for each fifteen (15) minute interval of the applicable Trading Hour, using the methodology set forth in Sections 31.2.2 and 31.2.3 above. If a Bid is mitigated in the MPM process for the first fifteen (15) minute interval for a Trading Hour, the mitigated Bid will be utilized for all market

applications for that first fifteen (15) minute interval. If a Bid is not mitigated in the first fifteen (15) minute interval, the CAISO will still mitigate that Bid in subsequent fifteen (15) minute intervals of the Trading Hour if the MPM runs for the subsequent intervals determine that mitigation is needed. For each Trading Hour, any Bid mitigated in a prior fifteen (15) minute interval of that Trading Hour will continue to be mitigated in subsequent intervals of that Trading Hour and may be further mitigated as determined in the MPM runs for any subsequent fifteen (15) minute interval. For HASP mitigation, a single mitigated Bid for the entire Trading Hour is calculated using the minimum Bid price of the four mitigated Bid curves at each Bid quantity level. For RMR Units, RMR Proxy Bids resulting from the MPM process will be utilized in all RTM optimization processes for each Trading Hour. For a Condition 1 RMR Unit, the use of RMR Proxy Bids is determined based on the non-competitive Congestion component of each LMP for each fifteen (15) minute interval of the applicable Trading Hour, using the methodology set forth in Section 31.2.2 above. If a Condition 2 RMR Unit is issued a Manual RMR Dispatch by the CAISO, then RMR Proxy Bids for all of the unit's Maximum Net Dependable Capacity will be considered in the MPM process. For both Condition 1 and Condition 2 RMR Units, when mitigation is triggered, a RMR Proxy Bid is calculated using the same methodology described above for non-RMR Units. For a Condition 1 RMR Unit that has submitted Bids and has not been issued a Manual RMR Dispatch, to the extent that the non-competitive Congestion component of an LMP calculated in the MPM process is greater than zero, and that MPM process dispatches a Condition 1 RMR Unit at a level such that some portion of its market Bid exceeds the Competitive LMP at the RMR Unit's Location, the resource will be flagged as an RMR dispatch if it is dispatched at a level higher than the dispatch level determined by the Competitive LMP. Both Condition 1 and Condition 2 RMR Units may be issued manual RMR dispatches at any time to address local reliability needs or to resolve non-competitive constraints.

34.1.6 Eligible Intermittent Resources Forecast

34.1.6.1 Eligible Intermittent Resources using their own Forecast

For Eligible Intermittent Resources, including Participating Intermittent Resources, that have elected to use the resource's own forecast as specified in Section 4.8.2.1.1, the responsible

Scheduling Coordinator must submit to the CAISO its forecast for the binding interval by 37.5 minutes prior to flow (the start of the applicable FMM optimization for the binding interval). If such Scheduling Coordinator does not provide such forecast to the CAISO, the CAISO will use the resource's direct telemetry MW output for Dispatch purposes. The CAISO shall use the forecast provided by the Scheduling Coordinator to establish MWh quantities to be cleared for that resource in the FMM if the resource has submitted only a Self-Schedule to the RTM. If a Scheduling Coordinator for a Variable Energy Resource submits an Economic Bid to the RTM (either with or without a Self-Schedule), then the CAISO receives and processes all Variable Energy Resources forecasts (as selected by CAISO) which establishes the upper economic limit for that resource in the FMM. Participating Intermittent Resources may elect not to use the forecast provided by the CAISO, in which case they must be certified to use their own forecast as provided in Section 4.8.2.1.1. In addition, the CAISO will not utilize the forecast it produces for the Participating Intermittent Resources using their own forecast. As provided in Section 4.8.2.1.1, the Scheduling Coordinator may submit such forecast in fifteen or five minute granularity. If the Scheduling Coordinator submits the forecast in five-minute granularity, the CAISO will use the average of the three five-minute forecasts provided by the Scheduling Coordinator to determine the MWh to be cleared in the FMM for that resource.

34.1.6.2 Eligible Intermittent Resources using the CAISO Forecast

Eligible Intermittent Resources that have elected to use the CAISO forecast as specified in Section 4.8.2.1.2 are not required to submit a forecast for the binding interval by 37.5 minutes prior to flow. For Participating Intermittent Resources for which Scheduling Coordinators have elected to use the output forecast provided by the CAISO and have selected such a flag in their Master File, the CAISO will use the MWh forecast data the CAISO produces for such a resource at 37.5 minutes prior to the applicable FMM as follows: (a) as the MWh amounts to be to cleared for that resource in the FMM if only a Self-Schedule is submitted, and (b) as the upper economic limit for that resource in the FMM if an Economic Bid with or without a Self-Schedule is submitted. The forecast used by the CAISO will be in fifteen-minute granularity. Scheduling Coordinators representing Participating Intermittent Resources whose output is designated to satisfy a

Resource Adequacy requirement must submit Variable Energy Resource Self-Schedules in the RTM in accordance with the output forecast provided by the CAISO, or an Economic Bid.

34.1.6.3 Participating Intermittent Resources under PIRP Protective Measures

For Participating Intermittent Resources that have elected PIRP Protective Measures, the CAISO will use a Self-Schedule of MWhs that is equal to the MWhs specified in the output forecast for that resource created by the CAISO ninety (90) minutes before the applicable Trading Hour to clear the resource in the RTM.

34.2 The Hour-Ahead Scheduling Process

34.2.1 The HASP Optimization

The Hour-Ahead Scheduling Process is a Real-Time Market process and a special run of the RTUC through which the CAISO accepts or rejects the following Bids submitted by Scheduling Coordinators at Scheduling Points: 1) Self-Schedule Hourly Blocks for Energy and Ancillary Services, 2) VER Self-Schedules for Energy, 3) Economic Hourly Block Bids for Energy and Ancillary Services, and 4) Economic Hourly Block Bids with Intra-Hour Option for Energy and providing an hourly schedule that can be changed at most once in the Trading Hour. The CAISO also produces advisory Energy schedules and Ancillary Services awards. Through the HASP, the CAISO may also issue binding unit commitment instructions for any resource participating in the RTM. After the Market Close for the RTM for the relevant Trading Hour, the RTM Bids have been validated, and the RTM Bids have been mitigated and the MPM process has been performed, the CAISO then conducts the HASP optimization. The CAISO does not accept Bids for CAISO Demand for any of the Real-Time Market processes. Therefore, CAISO clears Supply Bids against the CAISO Forecast Of CAISO Demand plus submitted Export Bids, to the extent the Export Bids are selected in the MPM process. The HASP optimization also factors in forecasted unscheduled flow at the Interties, as do all the Real-Time Market processes. The HASP optimization does not produce Settlement prices for Energy or Ancillary Services and the CAISO settles all Bids accepted through the HASP based on FMM Schedules and Awards and FMM LMPs and ASMPs.

34.2.2 Treatment of Self-Schedules in HASP

The HASP optimization does not adjust submitted Self-Schedule Hourly Blocks for Energy or Ancillary Services, or Self-Scheduled Variable Energy Resources unless it is not possible to balance Supply and the CAISO Forecast Of CAISO Demand plus Export Bids and manage Congestion using the available Economic Bids, in which case the HASP performs non-economic adjustments to Self-Schedules to accommodate operational restrictions. Once accepted, Self-Schedule Hourly Blocks for Energy or Ancillary Services are considered as Self-Schedules or Self-Provision, respectively, in each of the four FMM intervals. For accepted Variable Energy Resource Self-Schedules from external resources that are not Dynamic Schedules, the CAISO uses the Self-Schedule in the HASP optimization and the Scheduling Coordinator can update the Self-Schedule based on the most current Energy forecast, if it is qualified to do so by the CAISO and the Scheduling Coordinator registers it as such in the Master File. The HASP produces advisory MWh schedules for each of the four fifteen-minute intervals for FMM Economic Bids cleared in HASP, which can vary from the MWhs schedules cleared in the FMM. The MWh quantities of Self-Schedules of Supply that clear in the HASP constitute a feasible Dispatch for the Real-Time Market at the time HASP is executed, but the HASP results do not constitute a final Schedule for Generating Units because these resources may be adjusted for reasons other than economics in the FMM or RTD, if necessary to manage Congestion and clear Supply and Demand. The submission of a change to an ETC Self-Schedule beyond the deadline specified in Section 16.9.1, that is permitted pursuant to the terms of the applicable ETC, shall not be deemed to be an unbalanced ETC Self-Schedule for the purposes of Settlement, consistent with the ETC and TOR Self-Schedule Settlement treatment described in Section 11.5.7.

34.2.3 Ancillary Services in the HASP and FMM

All Operating Reserves procured in the Real-Time Market are Contingency Only Operating Reserves, as described in Section 30.5.2.6. Scheduling Coordinators submitting Ancillary Services Bids for Non-Dynamic System Resources in the Real-Time Market must also submit an Energy Bid under the same Resource ID for the associated Ancillary Services Bid. For these Non-Dynamic System Resources, the CAISO will only use the Ancillary Services Bid in the HASP optimization and will not Schedule Energy in the HASP, FMM, or RTD from the Energy Bid

provided under the same Resource ID as the Ancillary Services Bid. The CAISO may dispatch Energy from the Contingency Only Operating Reserves awarded to Non-Dynamic System Resources in the HASP through the Real-Time Contingency Dispatch as described in Section 34.5.2.

34.2.4 HASP Results

The CAISO publishes the results of the HASP processes no later than forty-five (45) minutes prior to the Trading Hour.

34.2.5 Cessation of the HASP

If, despite the variation of any time requirement or omission of any step, the CAISO is unable to operate any or all of the HASP processes, the CAISO may abort the HASP and perform all remaining Real-Time Market processes. When the CAISO aborts the HASP, Bids for HASP Block Intertie Schedules will revert to RUC Schedules and Day-Ahead Ancillary Service Awards.

34.3 Real-Time Unit Commitment

34.3.1 RTUC Optimization

The Real-Time Unit Commitment (RTUC) process uses SCUC and is run every fifteen (15) minutes to make commitment decisions for Fast Start and Short Start Units having Start-Up Times within the applicable time periods described below in this section for the next four to seven subsequent fifteen-minute intervals, depending on when during the hour the run occurs. For Multi-Stage Generating Resources the RTUC will issue a binding Transition Instruction separately from the binding Start-Up or Shut Down instructions. The RTUC can also be run with the Contingency Flag activated, in which case the RTUC can commit Contingency Only Operating Reserves. If RTUC is run without the Contingency Flag activated, it cannot commit Contingency Only Operating Reserves. RTUC is run at the following time intervals: (1) at approximately 7.5 minutes prior to the first Trading Hour, to serve as the HASP run, for T-45 minutes to T+60 minutes; (2) at approximately 7.5 minutes into the current hour for T-30 minutes to T+60 minutes; (3) at approximately 22.5 minutes into the current hour for T-15 minutes to T+60 minutes; and (4) at approximately 37.5 minutes into the current hour for T to T+60 minutes, where T is the beginning of the next Trading Hour. The HASP is a special RTUC run that is performed at

approximately 67.5 minutes before each Trading Hour and has the additional responsibility of pre-dispatching Energy and awarding Ancillary Services for HASP Block Intertie Schedules. A Day-Ahead Schedule or RUC Schedule for an MSG Configuration that is later impacted by the resource's derate or outages, will be reconsidered in the RTUC and the FMM taking into consideration the impacts of the derate or outage on the available MSG Configurations. Not all resources identified as needed in a given RTUC run will necessarily receive CAISO commitment instructions immediately, because during the Trading Day the CAISO may issue a commitment instruction to a resource only at the latest possible time that allows the resource to be ready to provide Energy when it is expected to be needed.

34.3.2 Commitment Of Fast Start And Short Start Units

RTUC produces binding and advisory Start-Up and Shut-Down Dispatch Instructions for Fast Start and Short Start Units that have Start-Up Times that would allow the resource to be committed prior to the end of the relevant time period of the RTUC run as described in Section 34.3.1. A Start-Up Dispatch Instruction is considered binding in any given RTUC run if the Start-Up Time of the resource is such that there would not be sufficient time for a subsequent RTUC run to Start-Up the resource. A Start-Up Instruction is considered advisory if it is not binding, such that the resource could achieve its target Start-Up Time as determined in the current RTUC run in a subsequent RTUC run based on its Start-Up Time. A Shut-Down Instruction is considered binding if the resource could achieve the target Shut-Down Time as determined in the current RTUC run in a subsequent RTUC run. A Shut-Down Dispatch Instruction is considered advisory if the resource Shut-Down Instruction is not binding such that the resource could achieve its target Shut-Down time as determined in the current RTUC run in a subsequent RTUC run. A binding Dispatch Instruction that results in a change in Commitment Status will be issued, in accordance with Section 6.3, after review and acceptance of the Start-Up Instruction by the CAISO Operator. An advisory Dispatch Instruction changing the Commitment Status of a resource may be modified by the CAISO Operator to a binding Dispatch Instruction and communicated in accordance with Section 6.3 after review and acceptance by the CAISO Operator. Only binding and not advisory Dispatch Instructions will be issued by the CAISO. For

Multi-Stage Generating Resources the CAISO will also issue binding Transition Instructions when the Multi-Stage Generating Resource must change from one MSG Configuration to another. A Transition Instruction is considered binding in any given RTUC run if the Transition Time for the Multi-Stage Generating Resource is such that there would not be sufficient time for a subsequent RTUC run to transition the resource.

34.4 Fifteen Minute Market

The CAISO conducts the Fifteen Minute Market using the second interval of each RTUC run horizon as follows: (1) at approximately 7.5 minutes prior to the first Trading Hour, for T-45 minutes to T+60 minutes where the binding interval is T-30 to T-15; (2) at approximately 7.5 minutes into the current hour for T-30 minutes to T+60 minutes where the binding interval is T-15 to T; (3) at approximately 22.5 minutes into the current hour for T-15 minutes to T+60 minutes for the binding interval T to T+15; and (4) at approximately 37.5 minutes into the current hour for T to T+60 minutes for the binding interval T+15 to T+30, where T is the beginning of the next Trading Hour. In these intervals the CAISO conducts the FMM to; (1) determine financially binding FMM Schedules and corresponding LMPs for all Pricing Nodes, including all Scheduling Points; (2) determine financially and operationally binding Ancillary Services Awards and corresponding ASMPs procure required additional Ancillary Services and calculate ASMP used for settling procured Ancillary Service capacity for the next fifteen-minute Real-Time Ancillary Service interval for all Pricing Nodes, including Scheduling Points; and (3) determine LAP LMPs that are the basis for settling Demand In any FMM interval that falls within a time period in which a Multi-Stage Generating Resource is transitioning from one MSG Configuration to another MSG Configuration, the CAISO: (1) will not award any incremental Ancillary Services; (2) will disqualify any Day-Ahead Ancillary Services Awards; (3) will disqualify Day-Ahead qualified Submissions to Self-Provide Ancillary Services Award, and (4) will disqualify Submissions to Self-Provide Ancillary Services in RTM. Each particular FMM market optimization produces binding settlement prices for Energy and Ancillary Services for the first FMM interval in the FMM horizon but the optimization considers the advisory results from subsequent market intervals within the FMM horizon. The CAISO settles Hourly Intertie Schedules and Hourly Ancillary Services Awards

accepted in the HASP as FMM Schedules and FMM Ancillary Services Awards in accordance with Section 11.5 and 11.10.1.2, respectively. In the event that a FMM run fails, the CAISO reverts to Day-Ahead Market Ancillary Services Awards and RUC Schedules results corresponding to the same interval, or the corresponding interval from the previous RTUC. The FMM will clear Supply against the CAISO Forecast Of CAISO Demand and exports. The FMM issues Energy Schedules and Ancillary Services Awards by twenty-two and a half minutes prior to the binding fifteen-minute interval.

34.4.1 Real-Time Ancillary Services Procurement

If the CAISO determines that additional Ancillary Services are required, other than those procured in the IFM, then the FMM will procure Ancillary Services on a fifteen (15) minute basis as necessary to meet reliability requirements and will determine Real-Time Ancillary Service interval ASMPs for such AS for the next Commitment Period. All Operating Reserves procured in the RTM are considered Contingency Only Operating Reserves. Any Ancillary Service awarded in FMM will be taken as fixed for the three (3) five (5) minute RTD intervals of its target fifteen (15) minute interval. In the FMM , all resources certified and capable of providing Operating Reserves that have submitted Real-Time Energy Bids shall also submit applicable Spinning or Non-Spinning Reserves Bids, respectively, depending on whether the resource is online or offline. The CAISO will utilize the RTM to procure Operating Reserves to restore its Operating Reserve requirements in cases when: (1) Operating Reserves awarded in the IFM have been dispatched to provide Energy, (2) resource(s) awarded to provide Operating Reserves in the IFM are no longer capable of providing such awarded Operating Reserves, or (3) the Operator determines that additional Operating Reserves are necessary to maintain Operating Reserves within NERC and WECC reliability standards, and any requirements of the NRC. The CAISO will utilize the FMM to procure additional Regulation capacity in Real-Time in cases when: (1) resource(s) awarded to provide Regulation in the IFM are no longer capable of providing such awarded Regulation, or (2) the Operator determines that additional Regulation is necessary to maintain sufficient control consistent with NERC and WECC reliability standards, and any requirements of the NRC and Good Utility Practice. The FMM will produce fifteen (15) minute ASMPs for the four

(4) binding fifteen (15) minute intervals for the applicable Trading Hour. These fifteen (15) minute ASMPs are then used for the Settlement of the fifteen (15) minute AS Awards. The FMM run will also produce fifteen (15) minute Shadow Prices for each of the Interties for the four (4) fifteen (15) minute intervals for the applicable Trading Hour. These fifteen (15) minute Shadow Prices are then used to charge for Intertie Real-Time AS Award providers for Congestion on the Interties. FMM AS Awards are settled in accordance with 11.10.1.3.

34.5 Real-Time Dispatch

The RTED uses a Security Constrained Economic Dispatch (SCED) algorithm every five (5) minutes throughout the Trading Hour to determine optimal Dispatch Instructions to balance Supply and Demand. The RTD can operate in three modes: RTED, RTCD and RTMD. In any given five-minute interval, the RTD optimization looks ahead over multiple five-minute intervals, but the CAISO issues Dispatch Instructions only for the next target five-minute interval. The CAISO will use the Real-Time Economic Dispatch (RTED) under most circumstances to optimally dispatch resources based on their Bids. The RTED can be used to Dispatch Contingency Only Operating Reserves, pursuant to Section 34.10, when needed to avoid an imminent System Emergency. The Real-Time Contingency Dispatch (RTCD) can be invoked in place of the RTED when a transmission or generation contingency occurs and will include all Contingency Only Operating Reserves in the optimization. If the CAISO awards a Non-Dynamic System Resource Ancillary Services in the IFM, HASP, or FMM and issues a Dispatch Instruction in the middle of the Trading Hour for Energy associated with its Ancillary Services (Operating Reserve) capacity, the CAISO will Dispatch the Non-Dynamic System Resource to operate at a constant level until the end of the Trading Hour. If the CAISO dispatches a Non-Dynamic System Resource such that the binding interval of the Dispatch is in the next Trading Hour, the CAISO will dispatch Energy from the Non-Dynamic System Resource at a constant level until the end of the next Trading Hour. The dispatched Energy will not exceed the awarded Operating Reserve capacity for the next Trading Hour and will be at a constant level for the entire next Trading Hour. The Real Time Manual Dispatch (RTMD) will be invoked as a fall-back mechanism only when the

RTED or RTCD fails to provide a feasible Dispatch. These three (3) modes of the RTD are described in Sections 34.5.1, 34.5.2, and 34.5.3.

34.5.1 Real-Time Economic Dispatch

RTED mode of operation for RTD normally runs every five (5) minutes starting at approximately 7.5 minutes prior to the start of the next Dispatch Interval and produces binding Dispatch Instructions for Energy for the next Dispatch Interval and advisory Dispatch Instructions for multiple future Dispatch Intervals through at least the next Trading Hour. After being reviewed by the CAISO Operator, only binding Dispatch Instructions are communicated for the next Dispatch Interval in accordance with Section 6.3. RTED will produce a Dispatch Interval LMP for each PNode for the Dispatch Interval associated with the binding Dispatch Instructions. The RTED Dispatch target is the middle of the interval between five (5) minutes boundary points. For Variable Energy Resources that forecast with 5 minute granularity, the CAISO will use the 5-minute forecast available prior to the start of the RTD optimization to determine the instructed Energy of the resource. RTD will return the 5-minute forecast value as the instructed Energy for the binding RTD interval provided that the Variable Energy Resource is optimized through the RTED.

34.5.2 Real-Time Contingency Dispatch

34.5.2.1 RTCD Mode

RTCD mode of operation for RTD is run in response to a significant Contingency event, such that waiting until the next normal RTD run is not adequate and/or Operating Reserves identified as Contingency Only need to be activated in response to the event. The CAISO Operator may activate Operating Reserves identified as Contingency Only either on a resource specific-basis or for all such resources. When activating Contingency Only reserves in RTCD, the original Energy Bids associated with the resources providing Operating Reserve will be used for the RTCD. RTCD uses SCED to produce an optimized set of binding Dispatch Instructions for one (1) or more ten-minute Dispatch Intervals instead of a normal five-minute Dispatch Interval. Resources must respond to RTCD Dispatch Instructions as soon as possible. After being reviewed by the CAISO Operator, only binding Dispatch Instructions are communicated for the next Dispatch

Interval in accordance with Section 6.3. When activating a RTCD and returning to normal RTED run after a RTCD run, five-minute Dispatch Interval LMPs will be produced for each PNode based on the last available price from either the RTCD or normal RTED run relative to a five-minute target Dispatch Interval.

34.5.2.2 RTDD Mode

RTDD is a special mode of the RTCD available to the CAISO Operator when 300 MW or more of capacity is needed to respond to a significant Contingency event. RTDD will not use SCED. Instead, RTDD will give Dispatch priority to Energy Bids from Operating Reserve capacity over Energy Bids from non-Operating Reserve capacity. RTDD will dispatch the Operating Reserve capacity in merit order and will then dispatch the non-Operating Reserve capacity in merit order based on available MW within the capacity's ten-minute ramping capability. As with the RTCD mode, in the RTDD mode, the CAISO Operator may activate Operating Reserves identified as Contingency Only either on a resource-specific basis or for all such resources. Resources must respond to RTDD Dispatch Instructions as soon as possible. During each ten-minute Dispatch Interval in which RTDD is employed, the Energy Bid of the highest-priced resource dispatched under RTDD will be used to set the Market Clearing Price on a system-wide basis for all resources dispatched under RTDD. The Market Clearing Price will not reflect Transmission Losses or Transmission Constraints.

34.5.3 Real-Time Manual Dispatch

RTMD mode of operation for RTD is a merit-order run activated upon CAISO Operator request as a backup process in case the normal RTED process fails to converge. The RTMD run will provide the CAISO Operator a list of resources and quantity of MW available for Dispatch in merit-order based on Operational Ramp Rate but otherwise ignores Transmission Losses and Transmission Constraints. The CAISO Operator may dispatch resources from the list by identifying the quantity of Imbalance Energy that is required for the system and/or directly selecting resources from the merit order taking into consideration actual operating conditions. After Dispatches have been selected, reviewed and accepted by the CAISO Operator, Dispatch Instructions will be communicated in accordance with Section 6.3. While the RTMD mode is

being used for Dispatch a uniform five-minute MCP will be produced for all PNodes based on the merit order Dispatch. Until RTMD is actually run and RTMD-based Dispatch Instructions are issued after RTED fails to converge, all five-minute Dispatch Interval LMPs will be set to the last LMP at each Node produced by the last RTED run that converged.

34.6 Short-Term Unit Commitment

Once per hour, near the top of each Trading Hour, immediately after the FMM and the RTUC for the same interval is completed the CAISO performs an approximately five (5) hour Short-Term Unit Commitment (STUC) run using SCUC and the CAISO Forecast Of CAISO Demand to commit Medium Start Units and Short Start Units with Start-Up Times greater than the time period covered by the RTUC described in Section 34.3. In any given Trading Hour, the STUC may commit resources for the third fifteen-minute interval of the current Trading Hour and extending into the next four (4) Trading Hours. The STUC looks ahead over a period of at least three (3) hours beyond the Trading Hour for which the RTUC optimization was run, and will utilize Bids available from other CAISO Markets for that Trading Hour for these additional hours. The CAISO revises these replicated Bids each time the hourly STUC is run, to utilize the most recently available Bids. Not all resources identified for need as a given STUC run will necessarily receive CAISO commitment instructions immediately, because during the Trading Day the CAISO may issue a commitment instruction to a resource only at the latest possible time that allows the resource to be ready to provide Energy when it is expected to be needed. A Start-Up Instruction produced by STUC is considered binding if the resource could not achieve the target Start-Up Time as determined in the current STUC run in a subsequent RTUC or STUC run as a result of the Start-Up Time of the resource. A Start-Up Instruction produced by STUC is considered advisory if it is not binding, such that the resource could achieve its target start time as determined in the current RTUC run in a subsequent STUC or RTUC run based on its Start-Up Time. A binding Dispatch Instruction produced by STUC that results in a change in Commitment Status will be issued, in accordance with Section 6.3, after review and acceptance of the Start-Up Instruction by the CAISO Operator. The STUC will only decommit a resource to the extent that resource's physical characteristics allow it to be cycled in the same approximately five (5) hour

look-ahead time period for which it was previously committed. STUC does not produce Locational Marginal Prices for Settlement. A Day-Ahead Schedule or RUC Schedule for an MSG Configuration that is later impacted by the resource's derate or outages, will be reconsidered in the STUC process taking into consideration the impacts of the derate or outage on the available MSG Configurations.

34.7 General Dispatch Principles

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

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

(2) In each run of the RTED or RTCD the objective will be to meet the projected Energy requirements over the applicable forward-looking time period of that run, subject to transmission and resource operational constraints, taking into account the short term CAISO Forecast Of CAISO Demand adjusted as necessary by the CAISO Operator to reflect scheduled changes to Interchange and non-dispatchable resources in subsequent Dispatch Intervals;

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

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

(5) The Dispatch Instructions of a resource for a subsequent Dispatch Interval shall take as a point of reference the actual output obtained from either the State Estimator solution or the last valid telemetry

measurement and the resource's operational ramping capability. For Multi-Stage Generating Resources the determination of the point of reference is further affected by the MSG Configuration and the information contained in the Transition Matrix;

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

(7) Through Start-Up Instructions the CAISO may instruct resources to start up or shut down, or may reduce Load for Participating Loads and Proxy Demand Resources, over the forward-looking time period for the RTM based on submitted Bids, Start-Up Costs and Minimum Load Costs, Pumping Costs and Pump Shut-Down Costs, as appropriate for the resource, or for Multi-Stage Generating Resource as appropriate for the applicable MSG Configuration, consistent with operating characteristics of the resources that the SCED is able to enforce. In making Start-Up or Shut-Down decisions in the RTM, the CAISO may factor in limitations on number of run hours or Start-Ups of a resource to avoid exhausting its maximum number of run hours or Start-Ups during periods other than peak loading conditions;

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

(9) The RTM optimization may result in resources being shut down consistent with their Bids and operating characteristics provided that: (a) the resource does not need to be on-line to provide Energy, (b) the resource is able to start up within the applicable time periods of the processes that comprise the RTM, (c) the Generating Unit is not providing Regulation or Spinning Reserve, and (d) Generating Units online providing Non-Spinning Reserve may be shut down if they can be brought up within ten (10) minutes as such resources are needed to be online to provide Non-Spinning Reserves;

(10) For resources that are both providing Regulation and have submitted Energy Bids for the RTM, Dispatch Instructions will be based on the Regulation Ramp Rate of the resource rather than the Operational Ramp Rate if the Dispatch Operating Point remains within the Regulating Range. The Regulating Range will limit the Ramping of Dispatch Instructions issued to resources that are providing Regulation;

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

(12) The CAISO may issue Transition Instructions to instruct resources to transition from one MSG Configuration to another over the forward-looking time period for the RTM based on submitted Bids, Transition Costs and Minimum Load Costs, as appropriate for the MSG Configurations involved in the MSG Transition, consistent with Transition Matrix and operating characteristics of these MSG Configurations. The RTM optimization will factor in limitations on Minimum Run Time and Minimum Down Time defined for each MSG configuration and Minimum

Run Time and Minimum Down Time at the Generating Unit or Dynamic Resource-Specific System Resource.

34.8 Dispatch Instructions to Units, Participating Loads, and PDR

The CAISO may issue Dispatch Instructions covering:

(a) Ancillary Services;

(b) Energy, which may be used for:

(i) Congestion relief;

(ii) provision of Imbalance Energy; or

(iii) replacement of an Ancillary Service;

(c) agency operation of Generating Units, Participating Loads, Proxy Demand Resources, or Interconnection schedules, for example:

(i) output or Demand that can be Dispatched to meet Applicable Reliability Criteria;

(ii) Generating Units that can be Dispatched for Black Start;

(iii) Generating Units that can be Dispatched to maintain governor control regardless of their Energy schedules;

(d) the operation of voltage control equipment applied on Generating Units as described in this CAISO Tariff;

(e) MSS Load following instructions provided to the CAISO, which the CAISO incorporates to create their Dispatch Instructions;

(f) necessary to respond to a System Emergency or imminent emergency; or

(g) Transition Instructions.

34.9 Utilization Of The Energy Bids

The CAISO uses Energy Bids for the following purposes: (i) satisfying Real-Time Energy needs; (ii) mitigating Congestion; (iii) maintaining aggregate Regulation reserve capability in Real-Time; (iv) allowing recovery of Operating Reserves utilized in Real-Time operations; (v) procuring Voltage Support required from resources beyond their power factor ranges in Real-Time; (vi)

establishing LMPs; (vii) as the basis for Bid Cost Recovery; and (viii) to the extent a Real-Time Energy Bid Curve is submitted starting at minimum operating level for a Short Start Unit that is scheduled to be on-line, the RTM may Dispatch such a resource down to its minimum operating level and may issue a Shut-Down Instruction to the resource based on its Minimum Load Energy costs.

34.10 Dispatch Of Energy From Ancillary Services

The CAISO may issue Dispatch Instructions to Participating Generators, Participating Loads, Proxy Demand Resources, (via communication with the Scheduling Coordinators of Demand Response Providers) System Units and System Resources contracted to provide Ancillary Services (either procured through the CAISO Markets, Self-Provided by Scheduling Coordinators, or dispatched in accordance with the RMR Contract) for the Supply of Energy. During normal operating conditions, the CAISO shall Dispatch those Participating Generators, Participating Loads, Proxy Demand Resources, System Units and System Resources that have contracted to provide Spinning and Non-Spinning Reserve, except for those reserves designated as Contingency Only, in conjunction with the normal Dispatch of Energy. Contingency Only reserves are Operating Reserve capacity that have been designated, either by the Scheduling Coordinator or the CAISO, as available to supply Energy in the Real-Time only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency. The CAISO may designate any reserve not previously identified as Contingency Only by Scheduling Coordinator as Contingency Only reserves, as necessary to maintain NERC and WECC reliability standards, including any requirements of the NRC. In the event of an unplanned Outage, a Contingency or a threatened or actual System Emergency, the CAISO may dispatch Contingency Only reserves. If Contingency Only reserves are dispatched through the RTCD, which as described in Section 34.5.2, only Dispatches in the event of a Contingency. Such Dispatch and pricing will be based on the original Energy Bids. If Contingency Only reserves are dispatched in response to a System Emergency that has occurred because the CAISO has run out of Economic Bids when no Contingency event has occurred, the RTED will Dispatch such Contingency Only reserves using maximum Bid prices as provided in Section 39.6.1 as the Energy Bids for such

reserves and will set prices accordingly. If a Participating Generator, Participating Load, System Unit or System Resource that is supplying Operating Reserve is dispatched to provide Energy, the CAISO shall replace the Operating Reserve as necessary to maintain NERC and WECC reliability standards, including any requirements of the NRC. If the CAISO uses Operating Reserve to meet Real-Time Energy requirements, and if the CAISO needs Operating Reserves to satisfy NERC and WECC reliability standards, including any requirements of the NRC, the CAISO shall restore the Operating Reserves to the extent necessary to meet NERC and WECC reliability standards, including any requirements of the NRC through either the procurement of additional Operating Reserve in the RTM or the Dispatch of other Energy Bids in SCED to allow the resources that were providing Energy from the Operating Reserve to return to their Dispatch Operating Point. The Energy Bid Curve is not used by the AGC system when Dispatching Energy from Regulation. For Regulation Up capacity, the upper portion of the resource capacity from its Regulation Limit is allocated to Regulation regardless of its Energy Bid Curve. For a resource providing Regulation Up or Operating Reserves the remaining Energy Bid Curve shall be allocated to any RTM AS Awards in the following order from higher to lower capacity where applicable: (a) Spinning Reserve; and (b) Non-Spinning Reserve. For resources providing Regulation Up, the applicable upper Regulation Limit shall be used as the basis of allocation if it is lower than the upper portion of the Energy Bid Curve. The remaining portion of the Energy Bid Curve, if there is any, shall constitute a Bid for RTM Energy. For Regulation Down capacity, the lower portion of the resource capacity from its applicable Regulation Limit is allocated to Regulation regardless of its Energy Bid Curve.

34.11 Exceptional Dispatch

The CAISO may issue Exceptional Dispatches for the circumstances described in this Section 34.11, which may require the issuance of forced Shut-Downs, forced Start-Ups, or forced MSG Transitions and shall be consistent with Good Utility Practice. Dispatch Instructions issued pursuant to Exceptional Dispatches shall be entered manually by the CAISO Operator into the Day-Ahead or RTM optimization software so that they will be accounted for and included in the communication of Day-Ahead Schedules and Dispatch Instructions to Scheduling Coordinators.

Exceptional Dispatches are not derived through the use of the IFM or RTM optimization software and are not used to establish the LMP at the applicable PNode. The CAISO will record the circumstances that have led to the Exceptional Dispatch. Except as provided in this Section 34.11, the CAISO shall consider the effectiveness of the resource along with Start-Up Costs, Transition Costs, and Minimum Load Costs when issuing Exceptional Dispatches to commit a resource to operate at Minimum Load. When the CAISO issues Exceptional Dispatches for Energy, the CAISO shall also consider Energy Bids, if available and as appropriate. In accordance with Good Utility Practice, the CAISO shall make CPM designations of Eligible Capacity for an Exceptional Dispatch by applying the following additional criteria in the order listed:

(1) the effectiveness of the Eligible Capacity at meeting the designation criteria specified in Section 43.2;

(2) the capacity costs associated with the Eligible Capacity;

(3) the quantity of a resource's available Eligible Capacity, based on a resource's PMin, relative to the remaining amount of capacity needed;

(4) the operating characteristics of the resource, such as dispatchability, Ramp Rate, and load-following capability; and

(5) whether the resource is subject to restrictions as a Use-Limited Resource.

In applying these selection criteria, the goal of the CAISO will be to issue Exceptional Dispatches on a least-cost basis to resources that will be effective in meeting the reliability needs underlying the Exceptional Dispatches. In making this determination, the CAISO will apply the first criterion to identify the effective Eligible Capacity by considering the effectiveness of the resources at meeting the designation criteria for the Exceptional Dispatch and at resolving the underlying reliability need. The CAISO will apply the second criterion by considering the cost of the effective Eligible Capacity. The CAISO will endeavor to Exceptionally Dispatch a resource at the CPM Capacity price determined in accordance with Section 43.6.1 before selecting a resource with a higher unit-specific CPM Capacity price specified under Section 43.6.2. The CAISO will endeavor to Exceptionally Dispatch resources that have specified a capacity price before

designating resources that have not specified a CPM Capacity price under Section 43.6.2.1. The CAISO will apply the third criterion by considering the quantity of a resource's Eligible Capacity. The CAISO will endeavor to select a resource that has a PMin at or below the capacity that is needed to meet the reliability need before selecting a resource that has a PMin that would result in over-procurement. The CAISO will apply the fourth criterion by considering specific operating characteristics of a resource, such as dispatchability, ramp rate, and load-following capability to the extent that such characteristics are an important factor in resolving the reliability need. The CAISO will apply the fifth criterion by considering whether a resource is use-limited and whether that status may restrict its ability to be available to the CAISO in the Day-Ahead Market and Real-Time Market throughout the period for which it is being procured. To the extent that use-limited resources are capable of performing the required service for the duration of the Exceptional Dispatch, the CAISO will not unduly discriminate in favor of non-Use Limited resources when applying the selection criteria. Imbalance Energy delivered or consumed pursuant to the various types of Exceptional Dispatch is settled according to the provisions in Section 11.5.6.

34.11.1 System Reliability Exceptional Dispatches

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

34.11.2 Other Exceptional Dispatch

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

34.11.3 Transmission-Related Modeling Limitations

The CAISO may also manually Dispatch resources in addition to or instead of resources with a Day-Ahead Schedule or dispatched by the RTM optimization software, during or prior to the Real-Time as appropriate, to address transmission-related modeling limitations in the Full Network Model. Transmission-related modeling limitations for the purposes of Exceptional Dispatch, including for settlement of such Exceptional Dispatch as described in Section 11.5.6, shall consist of any FNM modeling limitations that arise from transmission maintenance, lack of Voltage Support at proper levels as well as incomplete or incorrect information about the transmission network, for which the Participating TOs have primary responsibility. The CAISO shall also manually Dispatch resources under this Section 34.11.3 in response to system conditions including threatened or imminent reliability conditions for which the timing of the Real-Time Market optimization and system modeling are either too slow or incapable of bringing the CAISO Controlled Grid back to reliable operations in an appropriate time-frame based on the timing and physical characteristics of available resources to the CAISO.

34.11.4 Reporting Requirements

On the fifteenth day of each month, the CAISO shall file with the Commission and post to the CAISO Website an initial report concerning the Exceptional Dispatches that occurred in the month two months prior to the month in which the report is filed. The report shall identify the frequency, volume, costs, causes, and degree of mitigation of Exceptional Dispatches during such period to the extent such data are available. On the thirtieth day of the month following the month in which the initial report is filed, the CAISO shall file with the Commission and post to the CAISO Website a revised and updated report for the same period.

34.12 CAISO Market Adjustment To Non-Priced Quantities In The RTM

All Self-Schedules are respected by the SCED and SCUC to the maximum extent possible and are protected from curtailment in the Congestion Management process to the extent that there are effective Economic Bids that can relieve Congestion. If all Effective Economic Bids for the RTM are exhausted, all Self-Schedules between the Minimum Load and the lowest Energy level of the first Energy Bid point will be subject to uneconomic adjustments based on assigned scheduling priorities. This functionality of the optimization software is implemented through the setting of scheduling parameters as described in Section 27.4.3 and specified in Section 27.4.3.1 and the BPMs. Through this process, imports and exports may be reduced to zero, Demand may be reduced to zero, and Generation may be reduced to a lower operating limit (or Regulation Limit) (or to a lower Regulation Limit plus any qualified Regulation Down Award or Self-Provided Ancillary Services, if applicable). Any Self-Schedules below the Minimum Load level are treated as fixed Self-Schedules and are not subject to uneconomic adjustments for Congestion Management but may be subject to decommitment via an Exceptional Dispatch if necessary as a last resort to relieve Congestion that could not otherwise be managed.

34.12.1 Increasing Supply

The scheduling priorities as defined in the RTM optimization to meet the need for increasing Supply as reflected from higher to lower priority are as follows:

(a) Non-Participating Load reduction, exports explicitly identified in a Resource Adequacy Plan to be served by Resource Adequacy Capacity explicitly identified and linked in a Supply Plan to the exports, or Self-

Schedules for exports at Scheduling Points in the RTM served by Generation from non-Resource Adequacy Capacity or from non-RUC Capacity;

(b) Self-Schedules for exports at Scheduling Points in the RTM not offered by Generation from non-Resource Adequacy Capacity or not offered by Generation from non-RUC Capacity, except those exports explicitly identified in a Resource Adequacy Plan to be served by Resource Adequacy Capacity explicitly identified and linked in a Supply Plan to the exports as set forth in Section 34.12.1(a); and

(c) Contingency Only Operating Reserve if activated by Operator to provide Energy (as indicated by the Contingency Flag and the Contingency condition);

34.12.2 Decreasing Supply

The scheduling priorities as defined in the RTM optimization to meet the need for decreasing Supply as reflected from higher to lower priority are as follows:

(a) Non-Participating Load increase;

(b) Reliability Must Run (RMR) Schedule (Day-Ahead manual pre-dispatch or Manual RMR Dispatches or Dispatches that are flagged as RMR Dispatches following the MPM-RRD process);

(c) Transmission Ownership Right (TOR) Self-Schedule;

(d) Existing Rights (ETC) Self-Schedule;

(e) Regulatory Must-Run and Regulatory Must-Take (RMT) Self-Schedule;

(f) Participating Load increase;

(g) Day-Ahead Supply Schedule; and

(h) Self-Schedule Hourly Block These dispatch priorities as defined in the RTM optimization may be superseded by operator actions and procedures as necessary to ensure reliable operations.

34.13 Means Of Dispatch Communication

The CAISO dispatches Regulation by AGC to Participating Generators and, for Dynamic System Resources, through dedicated communication links that satisfy the CAISO's standards for external imports of Regulation. The CAISO communicates all other Dispatch Instructions electronically, except that, at the CAISO's discretion, the CAISO may communicate Dispatch Instructions by telephone, or facsimile. Scheduling Coordinators shall confirm the Dispatch Instructions that are communicated orally by repeating them to the CAISO employee providing the Dispatch Instruction. Except in the case of deteriorating system conditions or an actual or threatened System Emergency, and except for Dispatch Instructions for Regulation, the CAISO sends all Dispatch Instructions to the Scheduling Coordinator. The recipient Scheduling Coordinator shall immediately communicate the Dispatch Instruction to the operator of the resource. The CAISO may, with the prior permission of the applicable Scheduling Coordinator, communicate with and give Dispatch Instructions to the operators of the resource directly without having to communicate through their Scheduling Coordinator. The CAISO shall record the communications between the CAISO and Scheduling Coordinators relating to Dispatch Instructions in a manner that permits auditing of the Dispatch Instructions, and of the response of the resources, as applicable. In situations of deteriorating system conditions or System Emergency, the CAISO reserves the right to communicate directly with the resource(s) as required to ensure System Reliability. Scheduling Coordinators are required to advise the CAISO immediately of any change in resource availability that prevents the recipient of a Dispatch Instruction from performing in accordance with that Dispatch Instruction.

34.13.1 Response Required By Resources To Dispatch Instructions

Resources must:

(a) unless otherwise stated in the Dispatch Instruction, comply with a Dispatch Instruction immediately upon receipt;

(b) respond to all Dispatch Instructions in accordance with Good Utility Practice;

(c) meet voltage criteria in accordance with the provisions in the CAISO Tariff;

(d) meet any applicable Operational Ramp Rates;

(e) respond to Dispatch Instructions for Ancillary Services within the required time periods and (in the case of Participating Generators providing Regulation) respond to AGC from the EMS; and

(f) if a time frame is stated in a Dispatch Instruction, respond to a Dispatch Instruction within the stated time frame.

34.13.2 Failure To Conform To Dispatch Instructions

In the event that, in carrying out the Dispatch Instruction, an unforeseen problem arises (relating to plant operations or equipment, personnel or the public safety), the recipient of the Dispatch Instruction must notify the CAISO or, in the case of a Generator, the relevant Scheduling Coordinator immediately. The relevant Scheduling Coordinator shall notify the CAISO of the problem immediately. If a resource is unavailable or incapable of responding to a Dispatch Instruction, or fails to respond to a Dispatch Instruction in accordance with its terms, the resource shall be considered to be non-conforming to the Dispatch Instruction unless the resource has notified the CAISO of an event that prevents it from performing its obligations within thirty (30) minutes of the onset of such event through a SLIC log entry. Notification of non-compliance via the Automated Dispatch System (ADS) will not supplant nor serve as the official notification mechanism to the CAISO. If the resource is considered to be non-conforming as described above, the Scheduling Coordinator for the resource concerned shall be subject to Uninstructed Imbalance Energy as specified in Section 11.5.2 and Uninstructed Deviation Penalties as specified in Section 11.23. This applies whether any Ancillary Services concerned are contracted or Self-Provided. For a Non-Dynamic System Resource Dispatch Instruction prior to the Trading Hour, the Scheduling Coordinator shall inform the CAISO of its ability to conform to a Dispatch Instruction via ADS. The Non-Dynamic System Resource has the option to accept, partially accept, or decline the Dispatch Instruction, but in any case must respond within the timeframe specified in a Business Practice Manual. The Non-Dynamic System Resource can change its

response within the indicated timeframe. If a Non-Dynamic System Resource does not respond within the indicated timeframe, the Dispatch Instruction will be considered declined. A decline of such a Non-Dynamic System Resource for a Dispatch Instruction received at least forty (40) minutes prior to the Trading Hour will be subject to Uninstructed Deviation Penalties as specific in Section 11.23. A decline of such a Non-Dynamic System Resource for a Dispatch Instruction received less than forty (40) minutes prior to the Trading Hour will not be subject to Uninstructed Deviation Penalties. A Non-Dynamic System Resource that only partially accepts a Dispatch Instruction is subject to Uninstructed Deviation Penalties for the portion of the Dispatch Instruction that is declined.

When a resource demonstrates that it is not following Dispatch Instructions, the RTM will no longer assume that the resource will ramp from its current output level. The RTM assumes the resource to be "non-compliant" if it is deviating its five (5)-minute Ramping capability for more than N intervals by a magnitude determined by the CAISO based on its determination that it is necessary to improve the calculation of the expected Imbalance Energy as further defined in the BPM. When a resource is identified as "non-compliant," RTM will set the Dispatch operating target for that resource equal to its actual output in the Market Clearing software such that the persistent error does not cause excessive AGC action and consequently require CAISO to take additional action to comply with reliability requirements. Such a resource will be considered to have returned to compliance when the resource's State Estimator or telemetry value (whichever is applicable) is within the above specified criteria. During the time when the resource is "non-compliant", the last applicable Dispatch target shall be communicated to the Scheduling Coordinator as the Dispatch operating target. The last applicable Dispatch target may be (i) the last Dispatch operating target within the current Trading Hour that was instructed prior to the resource becoming "non-compliant," or (ii) the Day-Ahead Schedule, or (iii) awarded Self-Schedule Hourly Block depending on whether the resource submitted a Bid and the length of time the resource was "non-compliant," or (iv) for a Dynamic System Resource or a Pseudo-Tie Generating Unit that is an Eligible Intermittent Resource, the most recently available telemetry for the actual output.

34.14 Metered Subsystems

Scheduling Coordinators that represent MSSs may submit Bids for Supply of Energy to the RTM, irrespective of whether the MSS is a Load following MSS. All Bids submitted for MSS generating resources for the RTM and all Dispatch Instructions shall be generating resource-specific. MSS non-Load following resources are responsible for following Dispatch Instructions. Load following MSS Operators shall provide the CAISO with an estimate of the number of MWs the applicable generating resource(s) will be generating over the next two hours in five-minute interval resolution. The Dispatch Instructions for Load following resources are incorporated with Generation estimates provided by MSS Operators. Such MSS Load following resources can deviate from the Dispatch Instructions in Real-Time to facilitate the following of Load without being subject to the Uninstructed Deviation Penalty as further described in Section 11.23. The State Estimator will estimate all MSS Load in Real-Time and the CAISO will incorporate the information provided by the Load following MSS Operator for utilization in clearing the RTM and its Dispatch Instructions.

34.15 Treatment Of Resource Adequacy Capacity In The RTM

Resource Adequacy Resources required to offer their Resource Adequacy Capacity in accordance with Section 40 shall be required to submit Energy Bids for: (1) all such Resource Adequacy Capacity and (2) any Ancillary Services capacity awarded or self-provided in the IFM, HASP, or Real-Time Market. In the absence of submitted Bids, as part of the validation described in 30.7, Generated Bids will be used for Resource Adequacy Resources required to offer their Resource Adequacy Capacity in accordance with Section 40. For any capacity from a Resource Adequacy Resource not required to offer Resource Adequacy Capacity in accordance with Section 40 that was awarded or is self-providing Operating Reserves capacity in the IFM, Scheduling Coordinators must submit an Energy Bid for no less than the amount of awarded or self-provided Operating Reserves capacity above their Day-Ahead Schedule. Resource Adequacy Resources that are not required to offer their Resource Adequacy Capacity in accordance with Section 40 may voluntarily submit Energy Bids or Ancillary Services Bids.

Submitted Energy Bids shall be subject to the maximum and minimum Bid requirements and Mitigation Measures as set forth in Section 39.

34.16 Real-Time Activities In The Hour Prior To Settlement Period

34.16.1 Confirm Interchange Transaction Schedules (ITSs)

Also in the hour prior to the beginning of the Operating Hour the CAISO will:

(a) adjust Interchange transaction schedules (ITSs) as required under Existing Contracts in accordance with the procedures in the CAISO Tariff for the management of Existing Contracts;

(b) adjust ITSs as required by changes in transfer capability of transmission paths occurring after Market Close of the RTM; and

(c) agree on ITS changes with adjacent Balancing Authorities.

34.17 Rules For Real-Time Dispatch Of Imbalance Energy Resources

34.17.1 Resource Constraints

The SCED shall enforce the following resource physical constraints:

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

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

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

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

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

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

Generating Unit or Dynamic Resource-Specific System Resource and MSG Configuration.

(f) Operating (Spinning and Non-Spinning) Reserve. The SCED shall Dispatch Spinning and Non-Spinning Reserve subject to the limitations set forth in Section 34.18.3.

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

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

34.17.2 Calculation Of Dispatch Operating Points After Instructions

The RTED process shall calculate Dispatch Operating Points as follows:

(a) After the RTUC issues a Start-Up Instruction, RTED moves the Dispatch Operating Point of a resource immediately from zero (0) MW to the PMin, as defined in the Master File or as modified via SLIC, of a Generating Unit at the start of the Dispatch Interval pertaining to the Start-Up Instruction. The Dispatch Operating Point shall then be determined using the resource's applicable Operational Ramp Rate as further described in Sections 34.17.4, 34.17.5, and 34.17.6.

(b) After the RTUC issues a Shut-Down Instruction, RTED shall first ramp the Dispatch Operating Point down to the PMin, as defined in the Master File or as modified via SLIC, of a Generating Unit at the end of the

Dispatch Interval pertaining to the Shut-Down Instruction, using the resource's applicable Operational Ramp Rate. The Dispatch Operating Point shall then be set immediately to zero (0) MW.

(c) After the RTUC issues a Transition Instruction: (1) for MSG Configurations where the operating ranges of the two MSG Configurations do not overlap, the RTD will move the Dispatch Operating Point of the resource immediately from the boundary of the "from" MSG Configuration to the boundary of the "to" MSG Configuration, as defined in the Master File or as modified via the CAISO's outages reporting mechanism, of a Multi-Stage Generating Resource; and (2) for MSG Configurations for which the operating ranges of the two MSG Configurations do overlap, RTD will move the Dispatch Operating Point of the resource within the overlapping operating range of the MSG Configuration until the MSG Transition is complete.

34.17.3 [NOT USED]

34.17.4 Inter-Hour Dispatch Of Resources With Real-Time Energy Bids

Dispatch Instructions associated with the ramp between the Real-Time Market Bid in one hour and the Real-Time Market Bid in the immediately succeeding Trading Hour shall be determined optimally by the SCED if the CAISO has Bids for either or both relevant Operating Hours. For any Operating Hour(s) for which Bids have been submitted Dispatch Instructions will be optimized such that the Dispatch Operating Point is within the Bid range(s). For any Operating Hour without submitted Bids, Dispatch Instructions will be optimized such that the Dispatch Operating Point conforms to the Schedule within the Operating Hour. Energy resulting from the Standard Ramp shall be deemed Standard Ramping Energy and will be settled in accordance with Section 11.5.1. Energy resulting from any ramp extending beyond the Standard Ramp will be deemed Ramping Energy Deviation and will be settled in accordance with Section 11.5.1. Energy delivered or consumed as a result of CAISO Dispatch of a resource's Energy Bid in one Operating Hour to a Dispatch Operating Point such that the resource cannot return to its successive Operating Hour

Schedule or to an infra-marginal operating point by the beginning of the next Operating Hour is Residual Imbalance Energy and shall be settled as Instructed Imbalance Energy as provided for in Section 11.5.1 and also may be eligible for recovery of its applicable Energy Bid Costs in accordance with Section 11.8. Similarly, Energy delivered or consumed as a result of CAISO Dispatch of a resource's Energy Bid in a future Operating Hour to a Dispatch Operating Point different from its current Operating Point prior to the end of the current Operating Hour is also considered Residual Imbalance Energy and shall be settled as Instructed Imbalance Energy as provided for in Section 11.5.1 and also may be eligible for recovery of its applicable Energy Bid Costs in accordance with Section 11.8. When Ramping Energy Deviation and Residual Imbalance Energy coexist within a given Dispatch Interval, the Ramping Energy Deviation shall be the portion of Instructed Imbalance Energy that is produced or consumed within the Schedule-change band defined by the accepted RTM Bids of the two consecutive Settlement Periods; the Residual Imbalance Energy shall be the portion of Instructed Imbalance Energy that is produced or consumed outside the Schedule-change band.

34.17.5 Inter-Hour Resources Dispatch Without Real-Time Energy Bids

Dispatch Instructions shall be issued for each Dispatch Interval as needed to prescribe the ramp between a resource's accepted Self-Schedule in one Trading Hour and its accepted Self-Schedule in the immediately succeeding Trading Hour. Such Dispatch Instructions shall be based on the lesser of: (1) the applicable Operational Ramp Rate as provided for in Section 30.7.7 and (2) the Ramp Rate associated with the Standard Ramp. The Dispatch Instructions for Ramping of Generating Units without Real-Time Energy Bids in both Operating Hours shall ramp the resource between hourly Schedules symmetrically to the extent possible subject to the Regulation Ramping limitations across hourly boundaries in twenty (20) to sixty (60) minutes assuming Congestion can be resolved utilizing Economic Bids. The minimum twenty (20)-minute ramp is required for smooth hourly Schedule changes and is consistent with Intertie scheduling agreements between Balancing Authority Areas. Energy resulting from the Standard Ramp shall be deemed Standard Ramping Energy and will be settled in accordance with Section 11.5.1.

Energy resulting from any ramp extending beyond the Standard Ramp will be deemed Ramping Energy Deviation and will be settled in accordance with Section 11.5.1.

34.17.6 Intra-Hour Exceptional Dispatches

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

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

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

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

34.18 Ancillary Services In The Real-Time Market

34.18.1 Dispatch Of Self-Provided Ancillary Services

Where a Scheduling Coordinator has chosen to self-provide the whole of the additional Operating Reserve required to cover any Interruptible Imports which it has submitted through Self-Schedules in the Day-Ahead Market and has identified specific Generating Units, Participating Loads, System Units or System Resources as the providers of the additional Operating Reserve concerned, the CAISO shall Dispatch only the designated Generating Units, Participating Loads, System Units or System Resources in the event of the CAISO being notified that the on demand

obligation is being curtailed. The Scheduling Coordinator scheduling an Interruptible Import will be responsible for Operating Reserves associated with the Interruptible Import, regardless of whether the Scheduling Coordinator is an LSE or not. For all other Submissions to Self-Provide an Ancillary Service, the Energy Bid shall be used to determine the Dispatch, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 34.18.2.2.

34.18.2 Ancillary Services Requirements For RTM Dispatch

The following requirements apply to the Dispatch of Ancillary Services in the RTM:

34.18.2.1 Regulation

(a) Regulation provided from Generating Units or System Resources must meet the standards specified in this CAISO Tariff and Part A of Appendix K;

(b) The CAISO will Dispatch Regulation through the EMS, which Dispatch of Regulation by EMS does not set the RTM LMP;

(c) In the event of an unscheduled increase in system Demand or a shortfall in Generation output and Regulation margin drops, the CAISO will use Dispatch Energy in the RTM or Dispatch Operating Reserve to restore Regulation margin; and

(d) When scheduled Operating Reserve is used for restoration of Regulation reserve, the CAISO shall arrange for the replacement of that Operating Reserve.

34.182.2 Operating Reserve

(a) Spinning Reserve:

(i) Spinning Reserve provided from Generating Units and System Resources must meet the standards specified in Part B of Appendix K;

(ii) The CAISO will Dispatch Spinning Reserve as may be required to meet the Applicable Reliability Criteria;

(iii) The CAISO may Dispatch Spinning Reserve as balancing Energy to return Regulation Generating Units to their Set Points and restore full Regulation margin; and

(iv) The CAISO will Dispatch Spinning Reserve as determined by the SCED, subject to Sections 34.4 and 34.10.

(b) Non-Spinning Reserve:

(i) Non-Spinning Reserve provided from Generating Units, Demands, and System Resources must meet the standards specified in Part C of Appendix K;

(ii) The CAISO may Dispatch Non-Spinning Reserve in place of Spinning Reserve to meet Applicable Reliability Criteria;

(iii) The CAISO will Dispatch Non-Spinning Reserve as determined by the SCED, subject to Sections 34.4 and 34.10; and

(iv) The CAISO may Dispatch Non-Spinning Reserve to replace Spinning Reserve if there is a shortfall in Spinning Reserve because of a deficiency of balancing Energy.

34.18.2.3 Replacement of Operating Reserve

If Operating Reserve is used for Energy, the CAISO may replace such Operating Reserve through Dispatch of additional Energy available from Energy Bids submitted to the RTM or through procurement of additional reserves based on optimization of a resource's RTM Ancillary Service Bid and its Energy Bid.

34.18.2.4 Voltage Support

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

(b) The CAISO may Dispatch Generating Units to increase or decrease MVar output within power factor limits established pursuant to Section 8.2.3.3 (or within other limits specified by the CAISO in any exemption

granted pursuant to Section 8.2.3.3) at no cost to the CAISO when required for System Reliability.

(c) The CAISO may Dispatch each Generating Unit to increase or decrease MVar output outside of established power factor limits, but within the range of the Generating Unit's capability curve, at a price calculated in accordance with the CAISO Tariff.

(d) If Voltage Support is required in addition to that provided pursuant to Section 34.18.2.4 (b) and (c), the CAISO will reduce output of Participating Generators certified in accordance with Appendix K . The CAISO will select Participating Generators in the vicinity where such additional Voltage Support is required.

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

34.19 Dispatch Information And Instructions

34.19.1 Dispatch Information To Be Supplied By The CAISO

Communication of Dispatch information provided by the CAISO shall be in accordance with Section 6.3.

34.19.2 Dispatch Information To Be Supplied By SC

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

Operator provides to the Scheduling Coordinator regarding any change or potential change in the current status of all Generating Units, System Units and Intertie Schedules. This information includes any changes in MSS System Units and Generating Unit capacity that could affect planned Dispatch and conditions that could affect the reliability of the System Unit or Generating Unit.

34.19.3 Dispatch Information To Be Supplied By UDCs

Each UDC shall keep the CAISO informed of any change or potential change in the status of its transmission lines and station equipment at the point of Interconnection with the CAISO Controlled Grid. Each UDC shall keep the CAISO informed as to any event or circumstance in the UDC's service territory that could affect the reliability of the CAISO Controlled Grid. This would include adverse weather conditions, fires, bomb threats, etc.

34.19.4 Dispatch Information To Be Supplied By PTOs

Each PTO shall report any change or potential change in equipment status of the PTO's transmission assets turned over to the control of the CAISO or in equipment that affects transmission assets turned over to the control of the CAISO immediately to the CAISO (this will include line and station equipment, line protection, Remedial Action Schemes and communication problems, etc.). Each PTO shall also keep the CAISO immediately informed as to any change or potential change in the PTO's transmission system that could affect the reliability of the CAISO Controlled Grid. This would include adverse weather conditions, fires, bomb threats, etc.
Each PTO shall schedule all Outages of its lines and station equipment which are under the Operational Control of the CAISO in accordance with the appropriate procedures in Section 9.3. Each PTO shall coordinate any requests for or responses to Forced Outages on its transmission lines or station equipment which are under the Operational Control of the CAISO directly with the appropriate CAISO Control Center as defined in Section 7.1.

34.19.5 Dispatch Information To Be Supplied By Balancing Authorities

The CAISO and each adjacent Balancing Authority shall keep each other informed of any change or potential change in the status of the Interconnection and any changes in the Interconnection's TTC. The CAISO and each adjacent Balancing Authority shall keep each other informed of

situations such as adverse weather conditions, fires, etc., that could affect the reliability of any Interconnection.

The CAISO and each adjacent Balancing Authority shall follow all applicable NERC and WECC scheduling procedures. This will include checking the Interconnection schedules for the next Settlement Period prior to the start of the Energy ramp going into that hour. The CAISO and each adjacent Balancing Authority shall check and agree on actual MWh net Interchange after the hour for the previous Settlement Period. One Balancing Authority Area shall change its actual number to reflect that of the other Balancing Authority Area in accordance with WECC standard procedures.

The CAISO and each adjacent Balancing Authority shall exchange MW, MVar, terminal and bus voltage data with each other on a four second update basis. MWh data for the previous hour shall be exchanged once per hour. All MW and MWh data for both the CAISO Balancing Authority Area and the adjacent Balancing Authority Areas must originate from the same metering equipment. All provisions in Sections 4.6.1.1(i) and 4.6.1.1 (ii) refer to information and data obtained from metering used for Balancing Authority Area operations and not metering used for billing and Settlement.

34.20 Pricing Imbalance Energy

34.20.1 General Principles

Instructed and Uninstructed Imbalance Energy shall be paid or charged the applicable FMM or RTD LMP**.** These prices are determined using the Dispatch Interval LMPs. The Dispatch Interval LMPs shall be based on the Bid of the marginal Generating Units, System Units, Participating Loads, and Proxy Demand Resources dispatched by the CAISO to increase or reduce Demand or Energy output in each Dispatch Interval as provided in Section 34.20.2.1.

The CAISO will respond to the Dispatch Instructions issued by the SCED to the extent practical in the time available and acting in accordance with Good Utility Practice. The CAISO will record the reasons for any variation from the Dispatch Instructions issued by the SCED.

34.20.2 Determining Real-Time LMPs

34.20.2.1 Dispatch Interval Real-Time LMPs

34.20.2.2 Computation

For each Dispatch Interval, the CAISO will compute updated Imbalance Energy needs and will Dispatch Generating Units, System Units, Dynamic System Resources, Participating Load, and Proxy Demand Resources according to the CAISO's SCED during that time period to meet Imbalance Energy requirements. The RTM transactions will be settled at the Dispatch Interval LMPs in accordance with Section 11.5.

34.20.2.3 Eligibility to Set the Real-Time LMP

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

will not set the RTM LMP. Dispatches of Regulation resources to a Dispatch Operating Point by RTM SCED will be eligible to set the RTM LMP.

34.21 Temporary Waiver of Timing Requirements for the Real-Time Market

34.21.1 Criteria for Temporary Waiver of Timing Requirements

The CAISO may at its sole discretion implement any temporary variation or waiver of the timing requirements of this Section 34, Section 6.5.4, and Section 6.5.5 (including the omission of any step) if any of the following criteria are met:

(i) such waiver or variation of timing requirements is reasonably necessary to preserve System Reliability, prevent an imminent or threatened System Emergency or to retain Operational Control over the CAISO Controlled Grid during an actual System Emergency.

(ii) because of error or delay, the CAISO requires additional time to fulfill its responsibilities;

(iii) problems with data or the processing of data cause a delay in receiving or issuing Bids or publishing information on the CAISO's secure communication system;

(iv) problems with telecommunications or computing infrastructure cause a delay in receiving or issuing Day-Ahead Schedules or publishing information on the CAISO's secure communication system.

34.21.2 Information to be Published on Secure Communication System

If the CAISO temporarily implements a waiver or variation of such timing requirements, the CAISO will publish the following information on the CAISO's secure communication system as soon as practicable:

(i) the exact timing requirements affected;

(ii) details of any substituted timing requirements;

(iii) an estimate of the period for which this waiver or variation will apply; and

(iv) reasons for the temporary waiver or variation.

* * *

35.1 Market Validation

The CAISO shall monitor the Market Clearing software solutions for the Day-Ahead Market, the RUC process, and the Real-Time Market for all market intervals to determine whether prices are calculated accurately, consistent with the provisions of the CAISO Tariff. To the extent reasonably practicable, the CAISO shall correct erroneous prices identified through such monitoring and re-run the relevant CAISO Markets prior to publication of prices on its Open Access Same-Time Information System (OASIS) or provision of prices directly to Market Participants, if applicable.

* * *

37.3.1.1 Expected Conduct

Market Participants must submit Bids for Energy, RUC Capacity and Ancillary Services and Submissions to Self-Provide an Ancillary Service from resources that are reasonably expected to be available and capable of performing at the levels specified in the Bid, and to remain available and capable of so performing based on all information that is known to the Market Participant or should have been known to the Market Participant at the time of submission. Intertie Schedules in the RTM for import or export Energy are not subject to the foregoing requirement, but failure to deliver on such Intertie Schedules in the RTM can be subject to referral by DMM under Section 11.1, Appendix P.

* * *

39.7 Local Market Power Mitigation For Energy Bids

Local Market Power Mitigation is based on the assessment and designation of Transmission Constraints as competitive or non-competitive pursuant to Section 39.7.2. The local market power mitigation processes are described in Section 31.2 for the DAM and Sections 34.1.5 for the RTM.

* * *

39.7.2.1 Timing of Assessments

For the DAM and RTM, the CAISO will make assessments and designations of whether Transmission Constraints are competitive or non-competitive as part of the MPM runs associated with the DAM and RTM, respectively. Only binding Transmission Constraints determined by the MPM process will be assessed in the applicable market.

39.7.2.2 Criteria

Subject to Section 39.7.3, for the DAM and RTM, a Transmission Constraint will be non-competitive only if the Transmission Constraint fails the dynamic competitive path assessment pursuant to this Section 39.7.2.2.

(a) Transmission Constraints for the DAM – As part of the MPM process associated with the DAM, the CAISO will designate a Transmission Constraint for the DAM as non-competitive when the fringe supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow to the Transmission Constraint. For purposes of determining whether to designate a Transmission Constraint as non-competitive pursuant to this Section 39.7.2.2(a):

(i) Counter-flow to the Transmission Constraint means the delivery of Power from a resource to the system load distributed reference bus. If counter-flow to the Transmission Constraint is in the direction opposite to the market flow of Power to the Transmission Constraint, the counter-flow to the Transmission Constraint is calculated as the shift factor multiplied by the resource's scheduled Power. Otherwise, counter-flow to the Transmission Constraint is zero.

(ii) Fringe supply of counter-flow to the Transmission Constraint means all available capacity from internal resources not controlled by the identified potentially pivotal suppliers and all internal Virtual Supply Awards not controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. Available capacity reflects

the highest capacity of a resource's Energy Bid adjusted for Self-Provided Ancillary Services and derates.

(iii) Demand for counter-flow to the Transmission Constraint means all internal dispatched Supply and Virtual Supply Awards that provide counter-flow to the Transmission Constraint.

(iv) Potentially pivotal suppliers mean the three (3) portfolios of net sellers that control the largest quantity of counter-flow supply to the Transmission Constraint.

(v) Portfolio means the effective available internal generation capacity under the control of the Scheduling Coordinator and/or Affiliate determined pursuant to Section 4.5.1.1.12 and all effective internal Virtual Supply Awards of the Scheduling Coordinator and/or Affiliate. Effectiveness in supplying counter-flow is determined by scaling generation capacity and/or Virtual Supply Awards by the shift factor from that location to the Transmission Constraint being tested.

(vi) A portfolio of a net seller means any portfolio that is not a portfolio of a net buyer. A portfolio of a net buyer means a portfolio for which the average daily net value of Measured Demand minus Supply over a twelve (12) month period is positive. The average daily net value is determined for each portfolio by subtracting, for each Trading Day, Supply from Measured Demand and then averaging the daily value for all Trading Days over the twelve (12) month period. The CAISO will calculate whether portfolios are portfolios of net buyers in the third month of each calendar quarter and the calculations will go into effect at the start of the next calendar quarter. The twelve (12) month period used in this calculation will be the most recent twelve (12) month period for which data is available. The specific mathematical formula used to perform this calculation will be set forth in a Business Practice Manual. Market

Participants without physical resources will be deemed to be net sellers for purposes of this Section 39.7.2.2(a)(vi).

(vii) In determining which Scheduling Coordinators and/or Affiliates control the resources in the three (3) identified portfolios, the CAISO will include resources and Virtual Supply Awards directly associated with all Scheduling Coordinator ID Codes associated with the Scheduling Coordinators and/or Affiliates, as well as all resources that the Scheduling Coordinators and/or Affiliates control pursuant to Resource Control Agreements registered with the CAISO as set forth Section 4.5.1.1.13. Resources identified pursuant to Resource Control Agreements will only be assigned to the portfolio of the Scheduling Coordinator that has control of the resource or whose Affiliate has control of the resource pursuant to the Resource Control Agreements.

(b) Transmission Constraints for the RTM – As part of the MPM processes associated with the RTM, the CAISO will designate a Transmission Constraint for the RTM as non-competitive when the sum of the supply of counter-flow from all portfolios of potentially pivotal suppliers to the Transmission Constraint and the fringe supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow to the Transmission Constraint. For purposes of determining whether to designate a Transmission Constraint as non-competitive pursuant to this Section 39.7.2.2(b):

(i) Counter-flow to the Transmission Constraint has the meaning set forth in Section 39.7.2.2(a)(i).

(ii) Supply of counter-flow from all portfolios of potentially pivotal suppliers to the Transmission Constraint means the minimum available capacity from internal resources controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. The minimum

available capacity for the current market interval will reflect the greatest amount of capacity that can be physically withheld. The minimum available capacity is the lowest output level the resource could achieve in the current market interval given its dispatch in the last market interval and limiting factors including Minimum Load, Ramp Rate, Self-Provided Ancillary Services, Ancillary Service Awards (in the Real-Time Market only), and derates.

(iii) Potentially pivotal suppliers mean the three (3) portfolios of net sellers that control the largest quantity of counter-flow supply to the Transmission Constraint that can be withheld. Counter-flow supply to the Transmission Constraint that can be withheld reflects the difference between the highest capacity and the lowest capacity of a resource's Energy Bid (not taking into account the Ramp Rate of the resource), measured from the Dispatch Operating Point for the resource in the immediately preceding fifteen (15) minute FMM interval (taking into account the Ramp Rate of the resource), adjusted for Self-Provided Ancillary Services and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM, or adjusted for Ancillary Service Awards and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM. In determining whether to designate a Transmission Constraint as non-competitive for the RTM, counter-flow supply to the Transmission Constraint that can be withheld also reflects the PMin of each Short Start Unit with a Start-Up Time of sixty (60) minutes or less that was off-line in the immediately preceding fifteen (15) minute interval of the FMM. In determining whether to designate a Transmission Constraint as non-competitive for the RTM, counter-flow supply to the Transmission Constraint that can be withheld also reflects the PMin of each Short Start

Unit with a Start-Up Time of fifteen (15) minutes or less that was off-line in the immediately preceding fifteen (15) minute interval.

(iv) Portfolio means the effective available internal generation capacity under the control of the Scheduling Coordinator and/or Affiliate determined pursuant to Sections 4.5.1.1.12 and 39.7.2.2(a)(vii). Effectiveness in supplying counter-flow is determined by scaling generation capacity by the shift factor from that location to the Transmission Constraint being tested.

(v) A portfolio of a net seller has the meaning set forth in Section 39.7.2.2(a)(vi).

(vi) Fringe supply of counter-flow to the Transmission Constraint means all available capacity from internal resources not controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. Available capacity reflects the highest capacity of a resource's Energy Bid (not taking into account the Ramp Rate of the resource), measured from the Dispatch Operating Point for the resource in the immediately preceding fifteen (15) minute interval of the FMM (taking into account the Ramp Rate of the resource), adjusted for Self-Provided Ancillary Services and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM, or adjusted for Ancillary Service Awards and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM.

(vii) Demand for counter-flow to the Transmission Constraint means all internal dispatched Supply that provides counter-flow to the Transmission Constraint.

* * *

39.7.3 Default Competitive Path Designations

The CAISO will maintain default competitive path designation sets for the Day-Ahead Market and for the Real-Time Market, which the CAISO will use in order to determine the competitiveness or non-competitiveness of Transmission Constraints under two circumstances: (1) in the event of a failure of the CAISO Markets software to perform an assessment of whether Transmission Constraints are competitive or non-competitive pursuant to Section 39.7.2; and (2) in order to determine whether Exceptional Dispatches are related to a non-competitive Transmission Constraint for purposes of mitigation of Exceptional Dispatches of resources under Section 39.10(1). Default competitive path designations will be determined pursuant to the methodology set forth in this Section 39.7.3 and will be updated no less frequently than once every seven (7) days. Until the CAISO has developed sufficient information to develop default competitive path designations, the CAISO will continue to utilize the most recent list of competitive path designations determined prior to the effective date of this tariff provision.

* * *

39.7.3.4 Methodology for Determining RTM Default Competitive Path Designations for Path 15 and Path 26 Transmission Constraints

The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive for purposes of determining default competitive path designations for the RTM unless both of the following conditions are met:

(1) Congestion occurred on the Transmission Constraint in ten (10) or more of the hours for which the Transmission Constraint was tested for competitiveness pursuant to Section 39.7.2; and

(2) the Transmission Constraint was deemed competitive pursuant to Section 39.7.2 in fewer than seventy-five (75) percent of the instances in which the Transmission Constraint was binding when tested.

These calculations will be made utilizing data from the MPM for the Real-Time Market for the most recent sixty (60) Trading Days for which data is available. If the Transmission Constraint was binding during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be binding for the entire hour. If the Transmission Constraint was

determined to be non-competitive during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be non-competitive for the entire hour. The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive if the CAISO lacks sufficient data to determine whether the occurrences set forth in Sections 39.7.3.4(1) and 39.7.3.4(2) took place on the Transmission Constraint over the sixty (60) Trading Day period.

* * *

39.10.3 Eligibility For Supplemental Revenues

Except as provided in Section 39.10.4, a resource that is committed or dispatched under Exceptional Dispatch shall be eligible for supplemental revenues only during such times that the resource meets all of the following criteria:

(i) the resource has notified the CAISO, at least seven days prior to the calendar month in which the Exceptional Dispatch occurs, that the resource has chosen to receive supplemental revenues in lieu of an Exceptional Dispatch CPM designation under Section 43.1.5;

(ii) the resource has been mitigated under Section 39.10;

(iii) the resource is not under an RMR Contract, is not designated as CPM Capacity, and is not a Resource Adequacy Resource, unless the resource is a Partial Resource Adequacy Resource or a partial CPM resource, and the Exceptional Dispatch requires non-RA Capacity or non-CPM Capacity, in which case only the capacity not committed as Resource Adequacy Capacity or CPM Capacity is eligible for supplemental revenues; and

(iv) the resource has a Bid in the IFM and RTM for the applicable Operating Day or Operating Hour in which the resource is committed or dispatched under Exceptional Dispatch.

*** * ***

40.5.1 Day Ahead Scheduling And Bidding Requirements

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

(i) Local Capacity Area Resources physically capable of operating must submit: (a) Economic Bids for Energy and/or Self- Schedules for all their Resource Adequacy Capacity and (b) Economic Bids for Ancillary Services and/or a Submission to Self-Provide Ancillary Services for all of their Resource Adequacy Capacity that is certified to provide Ancillary Services. For Local Resource Adequacy Capacity that is certified to provide Ancillary Services and is not covered by a Submission to Self-Provide Ancillary Services, the resource must submit Economic Bids for each Ancillary Service for which the resource is certified. For Resource Adequacy

Capacity subject to this requirement for which no Economic Energy Bid or Self-Schedule has been submitted, the CAISO shall insert a Generated Bid in accordance with Section 40.6.8. For Resource Adequacy Capacity subject to this requirement for which no Economic Bids for Ancillary Services or Submissions to Self-Provide Ancillary Services have been submitted, the CAISO shall insert a Generated Bid in accordance with Section 40.6.8 for each Ancillary Service the resource is certified to provide. However, to the extent the Generating Unit providing Local Capacity Area Resource capacity constitutes a Use-Limited Resource under Section 40.6.4, the provisions of Section 40.6.4 will apply.

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

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

(iv) Through the IFM co-optimization process, the CAISO will utilize available Local Capacity Area Resource Adequacy Capacity to provide Energy or Ancillary Services in the most efficient manner to clear the Energy market, manage congestion and procure required Ancillary Services. In so doing the IFM will honor submitted Energy Self-Schedules of the Local Capacity Area Resource Adequacy Capacity of the Modified Reserve Sharing LSE unless the CAISO is unable to satisfy one hundred

(100) percent of the Ancillary Services requirements. In such cases the CAISO may curtail all or a portion of a submitted Energy Self-Schedule to allow Ancillary Service-certified Local Capacity Area Resource Adequacy Capacity to be used to meet the Ancillary Service requirements. The CAISO will not curtail for the purpose of meeting Ancillary Service requirements a Self-Schedule of a resource internal to a Metered Subsystem that was submitted by the Scheduling Coordinator for that Metered Subsystem. If the IFM reduces the Energy Self-Schedule of Resource Adequacy Capacity to provide an Ancillary Service, the Ancillary Service Marginal Price for that Ancillary Service will be calculated in accordance with Section 27.1.2 using the Ancillary Service Bids submitted by the Scheduling Coordinator for the Resource Adequacy Resource or inserted by the CAISO pursuant to this Section 40.5.1, and using the resource's Generated Energy Bid to determine the Resource Adequacy Resource's opportunity cost of Energy. If the Scheduling Coordinator for the Modified Reserve Sharing LSE's Resource Adequacy Resource believes that the opportunity cost of Energy based on the Resource Adequacy Resource's Generated Energy Bid is insufficient to compensate for the resource's actual opportunity cost, the Scheduling Coordinator may submit evidence justifying the increased amount to the CAISO and to the FERC no later than seven (7) days after the end of the month in which the submitted Energy Self-Schedule was reduced by the CAISO to provide an Ancillary Service. The CAISO will treat such information as confidential and will apply the procedures in Section 20.4 of this

CAISO Tariff with regard to requests for disclosure of such information. The CAISO shall pay the higher opportunity costs after those amounts have been approved by FERC.

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

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

* * *

40.5.4 Consequence Of Failure To Meet Scheduling Obligation

(1) If the Scheduling Coordinator for the Modified Reserve Sharing LSE fails to submit a Self-Schedule or submit Bids equal to 115% of its hourly Demand Forecasts for each Trading Hour for the next Trading Day in the IFM and RUC, the Scheduling Coordinator will be charged a capacity surcharge of three times the price of the relevant Day-Ahead Hourly LAP LMP in the amount of the shortfall. To the extent the Scheduling Coordinator for the Modified Reserve Sharing LSE schedules imports on one or more Scheduling Points in an aggregate megawatt amount greater than its aggregate import deliverability allocation under Section 40.4.6.2, the quantity of megawatts in excess

of its import deliverability allocation will not count toward satisfying the Modified Reserve Sharing LSE's scheduling obligation, unless it clears the Day-Ahead Market.

(2) If the Scheduling Coordinator for the Modified Reserve Sharing LSE cannot fulfill its obligations under Section 40.5.1(3), the Scheduling Coordinator for the Modified Reserve Sharing LSE will be charged a capacity surcharge of two times the average of the six (6) Settlement Interval LAP prices for the hour in the amount of the shortfall. Energy scheduled in the RTM will not net against, or be used as a credit to correct, any failure to fulfill the Day-Ahead IFM hourly scheduling and RUC obligation in Section 40.5.1(1).

(3) Any Energy surcharge received by the CAISO pursuant to this Section 40.5.4 shall be allocated to Scheduling Coordinators representing other Load Serving Entities in proportion to each such Scheduling Coordinator's Measured Demand during the relevant Trading Hour(s) to the aggregate CAISO Measured Demand during the relevant Trading Hour(s).

*** * ***

40.6.4.3.2 Hydro and Non-Dispatchable Use-Limited Resources

Hydroelectric Generating Units, Pumping Load, and Non-Dispatchable Use-Limited Resources shall submit Self-Schedules or Bids in the Day-Ahead Market for their expected available Energy or their expected as-available Energy, as applicable, in the Day-Ahead Market and RTM. Such resources shall also revise their Self-Schedules or submit additional Bids in RTM based on the most current information available regarding Expected Energy deliveries. Hydroelectric Generating Units, Pumping Load, and Non-Dispatchable Use-Limited Resources will not be subject to commitment in the RUC process. The CAISO will retain discretion as to whether a particular resource should be considered a Non-Dispatchable Use-Limited

Resource, and this decision will be made in accordance with the provisions of Section 40.6.4.1.

* * *

40.6.5 Additional Availability Requirements For System Resources

In the IFM, the multi-hour block constraints of a System Resource, other than a System Resource capable of submitting a Dynamic Schedule or a Resource-Specific System Resource, are honored in the optimization. Such a resource that is also a Resource Adequacy Resource must be capable of hourly scheduling by the CAISO in RUC if it is not fully scheduled in the IFM. If such a Resource Adequacy Resource is scheduled in the RUC, the CAISO will schedule the resource in the RTM for each hour of the resource's RUC schedule without regard to the multi-hour block constraint that was submitted to the IFM. For an existing System Resource that provides Resource Adequacy Capacity through a call-option that expires prior to the close of the IFM, such a System Resource listed on a Resource Adequacy Plan must be reported to the CAISO for consideration in the Extremely Long-Start Commitment Process.

* * *

40.6.7 Release Of Long Start Units

Long Start Units not committed in the Day-Ahead Market will be released from any further obligation to submit Self-Schedules or Bids for the relevant Operating Day. Scheduling Coordinators for Long Start Units are not precluded from self-committing the unit after the Day-Ahead Market and submitting a Self-Schedule for Wheeling-Out in the RTM, unless precluded by terms of their contracts.

* * *

40.6.8.1.2 Price Taker Option

The price taker option is a Generated Bid of $0/MWh plus the CAISO's estimate of the applicable grid management charge per MWh based on the gross amount of MWh scheduled in the DAM and RTM.

* * *

40.6.11 Curtailment Of Exports In Emergency Situations

At its sole discretion, the CAISO may curtail exports from Resource Adequacy Capacity to prevent or alleviate a System Emergency. An Export Bid or a Self-Schedule to provide exports included in a binding Schedule accepted in the IFM or RTM will not be distinguished from a Demand Bid or Self-Schedule to serve Load within the CAISO Balancing Authority Area included in a binding Schedule accepted in the IFM or RTM for purposes of curtailment under this Section, except as consistent with Good Utility Practice.

* * *

41.5.1 Day-Ahead And RTM RMR Dispatch

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

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

The Energy to be delivered for each Trading Hour pursuant to the RMR Dispatch Notice an RMR Dispatch in the IFM or Real-Time shall be referred to as the RMR Energy. Scheduling Coordinators may submit Bids in the DAM or the RTM for RMR Units operating under Condition 1 of the RMR Contract in accordance with the bidding rules applicable to non-RMR Units. A Bid submitted in the DAM or the RTM for a Condition 1 RMR Unit shall be deemed to be a notice of intent to substitute a market transaction for the amount of MWh specified in each Bid for each Trading Hour pursuant to Section 5.2 of the RMR Contract. In the event the CAISO issues an RMR Dispatch Notice or an RMR Dispatch in the IFM or Real-Time Market for any Trading Hour, any MWh quantities cleared through the MPM shall be considered as a market transaction in accordance with the RMR Contract. RMR Units operating as Condition 2

RMR Units may not submit Bids until and unless the CAISO issues an RMR Dispatch Notice or issues an RMR Dispatch in the IFM, in which case a Condition 2 RMR Unit shall submit Bids in accordance with the RMR Contract in the next available market for the Trading Hours specified in the RMR Dispatch Notice or Day-Ahead Schedule.

*** * ***

41.5.3 RMR Units And Ancillary Services Requirements

The CAISO may call upon RMR Units in any amounts that the CAISO has determined is necessary at any time after the issuance of Day-Ahead Schedules for the Trading Day if: (i) the CAISO determines that it requires more of an Ancillary Service than it has been able to procure, except that the CAISO shall not be required to accept Ancillary Services Bids that exceed the price caps specified in Section 39 or any other FERC-imposed price caps; and (ii) the CAISO has notified Scheduling Coordinators of the circumstances existing in this Section 41.5.3, and after such notice, the CAISO determines that a bid insufficiency condition in accordance with the RMR Contract exists in the RTM and the CAISO requires more of an Ancillary Service. The CAISO must provide the notice specified in sub paragraph (ii) of this Section 41.5.3 as soon as possible after the CAISO determines that additional Ancillary Services are needed for which Bids are not available. The CAISO may only determine that a Bid insufficiency exists after the Market Close of the RTM, unless an earlier determination is required in order to accommodate the RMR Unit's operating constraints. For the purposes of this Section 41.5.3, a Bid insufficiency exists in RTM if, and only if: (i) Bids in the RTM for the particular Ancillary Service that can be used to satisfy that particular Ancillary Services requirement that remain after first procuring the megawatts of the Ancillary Service that the CAISO had notified Scheduling Coordinators it would procure in the HASP ("remaining Ancillary Services requirement") represent, in the aggregate, less than two times such remaining Ancillary Services requirement; or (ii) there are less than two unaffiliated bidders to provide such remaining Ancillary Services requirement. If the CAISO determines that a Bid insufficiency condition exists as described in this Section 41.5.3, the CAISO may nonetheless accept available Bids if it determines in its sole discretion that the prices specified in the Bids

and the Energy Bid Curves created by the Bids indicate that the Scheduling Coordinators were not attempting to exercise market power.

* * *

Appendix A

Master Definition Supplement

* * *

- Alert, Warning Or Emergency (AWE) Notice

A CAISO operations communication issued to Market Participants and the public, under circumstances and in a form specified in CAISO Operating Procedures, when the operating requirements of the CAISO Controlled Grid are marginal because of Demand exceeding forecast, loss of major Generation sources, or loss of transmission capacity that has curtailed imports into the CAISO Balancing Authority Area, or if insufficient Bids for the Supply of Energy and Ancillary Services have been submitted in the RTM for the CAISO Balancing Authority Area.

* * *

- Ancillary Service Award Or AS Award

The notification by the CAISO indicating that a Bid to supply an Ancillary Service has been selected to provide such service in the DAM or RTM.

* * *

- Ancillary Service Schedule Or AS Schedule

The notification by the CAISO indicating that a Submission to Self-Provide an Ancillary Service has been selected to provide such service in the DAM or RTM.

* * *

- Bid Cost Recovery (BCR) Eligible Resources

Those resources eligible to participate in the Bid Cost Recovery as specified in Section 11.8, which include Generating Units, System Units, System Resources with RTM Economic bids, Participating Loads, and Proxy Demand Resources. A System Resource that has a Schedule that results from Bids submitted in violation of Section 30.5.5 shall not be a Bid Cost Recovery Eligible Resource for any Settlement Interval that occurs during the time period covered by the Schedule

that results from Bids submitted in violation of Section 30.5.5. Accepted Self-Schedule Hourly Blocks, cleared Economic Hourly Block Bids, and cleared Economic Hourly Block Bids with Intra-Hour Option are not eligible to participate in Bid Cost Recovery in the Real-Time Market.

* * *

- CAISO Markets

Any of the markets administered by the CAISO under the CAISO Tariff, including, without limitation, the DAM, RTM, transmission, and Congestion Revenue Rights.

- CAISO Markets Processes

The MPM, IFM, RUC, HASP, STUC, FMM, RTUC, and RTD.

* * *

- Commitment Interval

The fifteen minute period of time for which the CAISO commits resources or procures Ancillary Services through the FMM.

* * *

- Decline Monthly Charge – Exports

A charge that applies to the aggregate of a Scheduling Coordinator's HASP Block Intertie Schedules for Energy exports that are not delivered in a Trading Month, as determined pursuant to Section 11.31.1.

- Decline Monthly Charge – Imports

A charge that applies to the aggregate of a Scheduling Coordinator's HASP Block Intertie Schedules for Energy imports that are not delivered in a Trading Month, as determined pursuant to Section 11.31.1.

- Decline Potential Charge – Exports

A potential charge that is calculated for any HASP Block Intertie Schedule for an Energy export when the HASP Block Intertie Schedule is not delivered for any reason, which potential charge and its applicability are determined pursuant to Section 11.31.

- Decline Potential Charge – Imports

A potential charge that is calculated for any HASP Block Intertie Schedule for an Energy import

when the HASP Block Intertie Schedule is not delivered for any reason, which potential charge and its applicability are determined pursuant to Section 11.31.

- Decline Threshold Percentage – Imports/Exports

The rate at which Scheduling Coordinators may fail to deliver imports or exports in accordance with HASP Block Intertie Schedules without incurring Decline Monthly Charges – Imports or Decline Monthly Charges – Exports, as measured by the respective percentages of HASP Block Intertie Schedules for import or export MWh quantities that the Scheduling Coordinator does not deliver during a Trading Month. The Decline Threshold Percentage – Imports/Exports is ten percent (10%).

- Decline Threshold Quantity – Imports/Exports

The MWh quantity of HASP Block Intertie Schedules for imports or exports of Energy that a Scheduling Coordinator may fail to deliver during a Trading Month without incurring Decline Monthly Charges – Imports or Decline Monthly Charges – Exports. The Decline Threshold Quantity – Imports/Exports is 300 MWh.

* * *

- [Not Used]

* * *

- Eligible Intermittent Resource

A Variable Energy Resource that is a Generating Unit or Dynamic System Resource subject to a Participating Generator Agreement, Net Scheduled PGA, Dynamic Scheduling Agreement for Scheduling Coordinators, or Pseudo-Tie Participating Generator Agreement.

* * *

- Exceptional Dispatch

A Dispatch Instruction issued for the purposes specified in Section 34.11. Energy from Exceptional Dispatches shall not set any FMM or RTD LMP.

* * *

- [Not Used]

* * *

- Expected Energy

The total Energy that is expected to be generated or consumed by a resource, based on the Dispatch of that resource, as calculated by the Real-Time Market (RTM), and as finally modified by any applicable Dispatch Operating Point corrections. Expected Energy includes the Energy scheduled in the IFM, and it is calculated for the applicable Trading Day. Expected Energy is calculated for Generating Units, System Resources, Resource-Specific System Resources, Participating Loads, and Proxy Demand Resources. The calculation is based on the Day-Ahead Schedule and the Dispatch Operating Point trajectory for the three-hour period around the target Trading Hour (including the previous and following hours), the applicable FMM or RTD LMP for each Dispatch Interval of the target Trading Hour, and any Exceptional Dispatch Instructions. Energy from Non-Dynamic System Resources is converted into FMM Schedules. Expected Energy is used as the basis for Settlements.

* * *

- Fast Start Unit

A Generating Unit that has a Start-Up Time less than two hours and can be committed in the FMM and STUC.

* * *

- Fifteen Minute Market (FMM)

A Real-Time market procedure conducted throughout the Operating Day in fifteen-minute increments prior to the RTD, to clear Bids for Energy and Ancillary Services from imports and exports, internal Supply and CAISO Forecast Of CAISO Demand, as further specified in Section 34.5.

* * *

- FMM AS Award

An award of Ancillary Services established through the Fifteen Minute Market.

- FMM Derate Energy

Extra-marginal FMM IIE, exclusive of FMM Minimum Load Energy produced or consumed due to Minimum Load overrates or PMax derates. FMM Derate Energy is produced above the higher of

the Day-Ahead Schedule or the registered Minimum Load and below the lower of the overrated Minimum Load and the FMM Schedule, or consumed below the Day-Ahead Schedule and above the higher of the derated PMax or the FMM Schedule. There could be two FMM Derate Energy slices, one for the Minimum Load overrate, and one for the PMax derate. FMM Derate Energy does not overlap with FMM Minimum Load Energy, FMM Exceptional Dispatch Energy, or FMM Optimal Energy, but it may overlap with Day-Ahead Scheduled Energy and MSS Load Following Energy. FMM Derate Energy is settled as described in Section 11.5.1, and it is not included in BCR as described in Section 11.8.4.

- **FMM Exceptional Dispatch Energy**

Extra-marginal FMM IIE, exclusive of FMM Minimum Load Energy, and FMM Derate Energy, produced or consumed due to FMM Exceptional Dispatch Instructions that are binding in the relevant Dispatch Interval. Without MSS Load following, FMM Exceptional Dispatch Energy is produced above the LMP index and below the lower of the FMM Schedule or the FMM Exceptional Dispatch Instruction, or consumed below the LMP index and above the higher of the FMM Schedule or the FMM Exceptional Dispatch Instruction. The LMP index is the capacity in the relevant Energy Bid that corresponds to a Bid price equal to the relevant LMP. FMM Exceptional Dispatch Energy does not overlap with FMM Minimum Load Energy, FMM Derate Energy, or FMM Optimal Energy, but it may overlap with Day-Ahead Scheduled Energy, RTD Optimal Energy, and MSS Load Following Energy. FMM Exceptional Dispatch Energy is settled as described in Section 11.5.6, and it is not included in BCR as described in Section 11.8.4.

* * *

- FMM IIE Settlement Amount

The payment due a Scheduling Coordinator for positive FMM Instructed Imbalance Energy or the charge assessed on a Scheduling Coordinator for negative FMM Instructed Imbalance Energy, as calculated pursuant to Section 11.5.1.1

- FMM Instructed Imbalance Energy (FMM IIE)

The portion of Imbalance Energy resulting from Day-Ahead Schedules and FMM Schedules determined pursuant to Section 11.5.1.

- FMM Minimum Load Energy

FMM IIE produced due to the Minimum Load of a Generating Unit that is committed in the RUC or the FMM and does not have a Day-Ahead Schedule or of a Constrained Output Generator (COG) that is committed in the IFM with a Day-Ahead Schedule below the registered Minimum Load. If the resource is committed in the FMM for Load following by an MSS Operator, the FMM Minimum Load Energy is accounted as MSS Load Following Energy instead. FMM Minimum Load Energy is FMM IIE above the Day-Ahead Schedule (or zero if there is no Day-Ahead Schedule of Energy) and below the registered Minimum Load. FMM Minimum Load Energy does not overlap with any other Expected Energy type. FMM Minimum Load Energy is settled as described in Section 11.5.1, and it is included in BCR as described in Section 11.8.4.1.2. FMM IIE that is consumed when a resource that is scheduled in the DAM is shut down in the FMM is accounted as FMM Optimal Energy and not as FMM Minimum Load Energy.

- FMM MSS Price

1) The Hourly LAP price for the MSS when the MSS internal metered Demand exceeds the MSS internal measured Generation; or 2) the weighted average of the FMM LMPs for all applicable PNodes within the relevant MSS when MSS internal measured Generation exceeds MSS internal Measured Demand where weighting factors for computing the weighted average are based on the measured Energy of all Generation at the corresponding PNodes.

- FMM Non-Overlapping Optimal Energy

The portions of FMM Optimal Energy that are not FMM Overlapping Optimal Energy, which are indexed against the relevant Energy Bid and sliced by Energy Bid price.

- FMM Optimal Energy

Any remaining FMM IIE after accounting for all other FMM IIE subtypes. FMM Optimal Energy does not overlap with FMM Minimum Load Energy, FMM Derate Energy, and FMM Exceptional Dispatch Energy, but it may overlap with Day-Ahead Scheduled Energy, and MSS Load Following Energy. FMM Optimal Energy is indexed against the relevant Energy Bid and sliced by service type, depending on the AS capacity allocation on the Energy Bid. FMM Optimal Energy is also divided into FMM Overlapping Optimal Energy and FMM Non-Overlapping Optimal Energy.

Any FMM Optimal Energy slice below or above the Energy Bid has no associated Energy Bid price, and it is not included in BCR as described in Section 11.5.

- FMM Overlapping Optimal Energy

The portion of FMM Optimal Energy that overlaps with MSS Load Following Energy.

- FMM Schedule

The binding output of the FMM resulting from Bids submitted to the RTM. The portion of a HASP Block Intertie Schedule for either Energy or Ancillary Services that becomes financially binding shall constitute a FMM Schedule.

* * *

- Forced Outage

An Outage for which sufficient notice cannot be given to allow the Outage to be factored into the Day-Ahead Market or RTM bidding processes.

* * *

- HASP Advisory Schedule

The output of the HASP that is not a HASP Block Intertie Schedule.

- [Not Used]

- [Not Used]

- [Not Used]

- **HASP Block Intertie Schedule**

The output of the HASP resulting from accepted Self-Schedule Hourly Blocks and awarded Economic Hourly Block Bids (but excluding an Economic Hourly Block Bid with Intra-Hour option). A HASP Block Intertie Schedule can include Energy and AS. HASP Block Intertie Schedules, as modified after accepted, are settled at the applicable FMM LMP and FMM ASMPs. HASP Block Intertie Schedules are advisory only in that they may be curtailed by the CAISO for Reliability reasons. Otherwise, the MWH quantity of a HASP Block Intertie Schedule is financially binding.

- [Not Used]

- [Not Used]

- [Not Used]

* * *

- [Not Used]

* * *

Hour-Ahead Scheduling Process (HASP)

The process conducted by the CAISO beginning at seventy-five minutes prior to the Trading Hour through which the CAISO conducts the activities specified in Section 34.2.

* * *

- [Not Used]

* * *

- [Not Used]

* * *

- Inter-SC Trade Period

Either the Day-Ahead Inter-SC Trade Period or the RTM Inter-SC Trade Period.

* * *

- Market Clearing

The act of conducting any of the processes used by the CAISO to determine LMPs, Day-Ahead Schedules, RUC Awards or AS Awards, HASP Block Intertie Schedules, FMM Schedules and Dispatch Instructions based on Supply Bids and Demand Bids or CAISO Demand Forecast.

* * *

- Market Close

The time after which the CAISO is no longer accepting Bids for its CAISO Markets which: 1) for the DAM is 10:00 A.M. Pacific Time of the Day-Ahead; and 2) for RTM is approximately seventy-five minutes prior to the Operating Hour.

* * *

- Market Power Mitigation - RRD

The two-optimization run process conducted in both the Day-Ahead Market and the RTM that determines the need for the CAISO to employ market power mitigation measures or Dispatch RMR Units.

* * *

- MSS Load Following Energy

RTD IIE, exclusive of Standard Ramping Energy, Ramping Energy Deviation, and Residual Imbalance Energy, produced or consumed due to Load following by an MSS. MSS Load Following Energy is the RTD IIE that corresponds to the algebraic Qualified Load Following Instruction, relative to the Day-Ahead Schedule. MSS Load Following Energy does not coexist with FMM Optimal Energy, and it does not overlap with Standard Ramping Energy, Ramping Energy Deviation, or Residual Imbalance Energy, but it may overlap with Day-Ahead Scheduled Energy, RTD Derate Energy, RTD Exceptional Dispatch Energy, and RTD Optimal Energy. MSS Load Following Energy is settled as provided in Section 11.5.1, and it is not included in BCR as described in Section 11.8.4.

* * *

- Net Procurement

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

* * *

- [Not Used]

* * *

- Non-priced Quantity

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

* * *

- Non-Spinning Reserve Cost

The revenues paid to the suppliers of the total awarded Non-Spinning Reserve capacity in the Day-Ahead Market and Real-Time Market, minus, the payments rescinded due to either the failure to conform to CAISO Dispatch Instructions or the unavailability of the Non-Spinning Reserves under Section 8.10.8.

* * *

- Operational Adjustment

The difference between the Energy scheduled in the Balancing Authority Area check-out process for Scheduling Points and the FMM Schedule for Non-Dynamic System Resources.

* * *

- [Not Used]

* * *

- [Not Used]

* * *

- Persistent Deviation Metric

A threshold metric used to evaluate a resource's change in output between Settlement Intervals relative to the change in Dispatch by the CAISO between Settlement Intervals. The Persistent Deviation Metric is applied by Settlement Interval and is applied for the twenty-four five-minute Settlement Intervals that comprise the previous two Trading Hours. Thus, the evaluation window is a rolling two hours, incrementing in hourly Settlement Intervals. The Persistent Deviation Metric for each Settlement Interval (t) is measured as the ratio of: (1) Metered Energy in the prior Settlement Interval (t-1), less the Metered Energy in the given Settlement Interval (t); and (2) Metered Energy in the prior Settlement Interval (t-1), less the Expected Energy in the given Settlement Interval (t), and less the Regulation Energy in the given Settlement Interval (t).

* * *

- PIRP Protective Measures

The temporary Settlement treatment delineated in Section 11.12.1 that is provided to Participating Intermittent Resources that qualify to receive such treatment under Section 4.8.1 and that complete their election to receive such treatment no later than thirty (30) days after the effective date of Section 4.8.1

* * *

- Real-Time Congestion Offset

For each Settlement Period of the RTM, the CAISO shall calculate the Real-Time Congestion Offset as the difference of 1) the sum of the products of the total of the Demand Imbalance Energy and Virtual Supply liquidated as demand in the RTM and the RTM MCC at the relevant Location; and 2) the sum of the products of the total of the Supply Imbalance Energy and Virtual Demand liquidated as supply in the RTM, and the RTM MCC at the relevant Location; including also the sum of RTM Congestion Charges for Intertie Ancillary Services Awards, and excluding the RTM Congestion Credit for ETCs and TORs calculated as provided in Section 11.5.7.1. The Real-Time Congestion Offset is allocated as provided in Section 11.5.4.2.

* * *

- Real-Time Market (RTM)

The spot market conducted by the CAISO using SCUC and SCED in the Real-Time which includes the HASP, FMM, STUC and the RTD for the purpose of Unit Commitment, Ancillary Service procurement, Congestion Management and Energy procurement based on Supply Bids and CAISO Forecast Of CAISO Demand.

- Real-Time Market Pumping Bid Cost

For the applicable Settlement Interval, the Pumping Cost submitted to the CAISO in the RTM divided by the number of Settlement Intervals in a Trading Hour, as further provided in Section 11.8.4.1.4.

* * *

- [Not Used]

- [Not Used]

- [Not Used]

- [Not Used]

- Real-Time Unit Commitment (RTUC)

An application of the RTM that runs every 15 minutes and commits Fast Start Units and Medium Start Units using the SCUC to adjust from Day-Ahead Schedules and HASP Advisory Schedules.

* * *

- [Not Used]

* * *

- RTD Derate Energy

Extra-marginal RTD IIE, exclusive of FMM IIE, Standard Ramping Energy, Ramping Energy Deviation, Residual Imbalance Energy, MSS Load Following Energy, and RTD Minimum Load Energy produced or consumed due to Minimum Load overrates or PMax derates. RTD Derate Energy is produced above the higher of the FMM Schedule or the registered Minimum Load, and below the lower of the overrated Minimum Load and the Dispatch Operating Point, or consumed below the lower of the FMM Schedule, and above the higher of the derated PMax or the Dispatch Operating Point. There could be two RTD Derate Energy slices, one for the Minimum Load overrate, and one for the PMax derate. RTD Derate Energy does not overlap with FMM IIE, Standard Ramping Energy, Ramping Energy Deviation, Residual Imbalance Energy, RTD Minimum Load Energy, RTD Exceptional Dispatch Energy, or RTD Optimal Energy, but it may overlap with Day-Ahead Scheduled Energy and MSS Load Following Energy. RTD Derate Energy is settled as described in Section 11.5.1, and it is not included in BCR as described in Section 11.8.4.

- **RTD Exceptional Dispatch Energy**

Extra-marginal RTD IIE, exclusive of FMM IIE, Standard Ramping Energy, Ramping Energy Deviation, Residual Imbalance Energy, MSS Load Following Energy, RTD Minimum Load Energy, and RTD Derate Energy, produced or consumed due to RTD Exceptional Dispatch Instructions that are binding in the relevant Dispatch Interval. Without MSS Load following, RTD Exceptional Dispatch Energy is produced above the LMP index and below the lower of the Dispatch Operating Point or the RTD Exceptional Dispatch Instruction, or consumed below the

LMP index and above the higher of the Dispatch Operating Point or the RTD Exceptional Dispatch Instruction. The LMP index is the capacity in the relevant Energy Bid that corresponds to a Bid price equal to the relevant LMP. RTD Exceptional Dispatch Energy does not overlap with FMM IIE, Standard Ramping Energy, Ramping Energy Deviation, Residual Imbalance Energy, RTD Minimum Load Energy, RTD Derate Energy, or RTD Optimal Energy, but it may overlap with Day-Ahead Scheduled Energy and MSS Load Following Energy. RTD Exceptional Dispatch Energy is settled as described in Section 11.5.6, and it is not included in BCR as described in Section 11.8.4.

- RTD IIE Settlement Amount

The payment due a Scheduling Coordinator for positive RTD Instructed Imbalance Energy or the charge assessed on a Scheduling Coordinator for negative RTD Instructed Imbalance Energy, as calculated pursuant to Section 11.5.1.2.

- RTD Imbalance Energy

The deviation of Supply or Demand from FMM Schedule, positive or negative, as measured by metered Generation, metered Load, or Real-Time Interchange Schedules. RTD Imbalance Energy is composed of RTD Instructed Imbalance Energy and Uninstructed Imbalance Energy.

- RTD Instructed Imbalance Energy (RTD IIE)

The portion of Imbalance Energy resulting from Dispatch Instructions and FMM Schedules.

- RTD Minimum Load Energy

RTD IIE, exclusive of Standard Ramping Energy, Ramping Energy Deviation, and Residual Imbalance Energy, produced due to the Minimum Load of a Generating Unit that is committed in the RUC or the RTM and does not have a Day-Ahead Schedule or a Constrained Output Generator (COG) that is committed in the IFM with a Day-Ahead Schedule below the registered Minimum Load. If the resource is committed in RTM for Load following by an MSS Operator, the RTD Minimum Load Energy is accounted as MSS Load Following Energy instead. RTD Minimum Load Energy is RTD IIE above the Day-Ahead Schedule (or zero if there is no Day-Ahead Schedule of Energy) and below the registered Minimum Load. RTD Minimum Load Energy does not overlap with any other Expected Energy type. RTD Minimum Load Energy is settled as

described in Section 11.5.1, and it is included in BCR as described in Section 11.8.4.1.2. RTD IIE that is consumed when a resource that is scheduled in the DAM is shut down in the RTM is accounted as RTD Optimal Energy and not as RTD Minimum Load Energy.

- RTD MSS Price

1) The RTD LAP price for the MSS when the MSS internal metered Demand exceeds the MSS internal measured Generation; or 2) the weighted average of the RTD LMPs for all applicable PNodes within the relevant MSS when MSS internal measured Generation exceeds MSS internal Measured Demand where weighting factors for computing the weighted average are based on the measured Energy of all Generation at the corresponding PNodes.

- RTD Non-Overlapping Optimal Energy

The portions of RTD Optimal Energy that are not RTD Overlapping Optimal Energy, which are indexed against the relevant Energy Bid and sliced by Energy Bid price.

- RTD Optimal Energy

Any remaining RTD IIE after accounting for all other RTD IIE subtypes. RTD Optimal Energy does not overlap with FMM Optimal Energy Standard Ramping Energy, Ramping Energy Deviation, Residual Imbalance Energy, RTD Minimum Load Energy, RTD Derate Energy, and RTD Exceptional Dispatch Energy, but it may overlap with Day-Ahead Scheduled Energy, and MSS Load Following Energy. RTD Optimal Energy is indexed against the relevant Energy Bid and sliced by service type, depending on the AS capacity allocation on the Energy Bid. Optimal Energy is also divided into RTD Overlapping Optimal Energy and RTD Non-Overlapping Optimal Energy. Any RTD Optimal Energy slice below or above the Energy Bid has no associated Energy Bid price, and it is not included in BCR as described in Section 11.5.1.1.

- RTD Overlapping Optimal Energy

The portion of RTD Optimal Energy that overlaps with MSS Load Following Energy.

- RTD Pumping Energy

RTD IIE from a Participating Load Pumped-Storage Hydro Unit or Pumping Load, exclusive of Standard Ramping Energy and Ramping Energy Deviation, consumed below the Day-Ahead Schedule when dispatched in pumping mode, or produced from pumping operation due to

pumping level reduction in Real-Time Dispatch, including pump shut-down. RTD Pumping Energy does not overlap with any other RTD Expected Energy type. RTD Pumping Energy is settled as described in Section 11.5.1, and it is included in BCR as described in Section 11.8.4.1.4.

* * *

- RTM Congestion Credit

A credit provided to Scheduling Coordinators to offset any RTM Congestions Charges that would otherwise be applied to the valid and balanced portions of any ETC or TOR Self-Schedules in the Real-Time Market as provided in Section 11.5.7.

* * *

- RTM Inter-SC Trade Period

The period commencing at midnight (0000 hours) on the applicable Trading Day and ending at forty-five (45) minutes prior to the start of the applicable Operating Hour, during which time the CAISO will accept from Scheduling Coordinators Inter-SC Trades of Energy to the RTM, Inter-SC Trades of Ancillary Services, and Inter-SC Trades of IFM Load Uplift Obligations.

- RTM MCL Credit For Eligible TOR Self-Schedules

A credit provided to Scheduling Coordinators pursuant to Section 17.3.3 to offset any RTM Marginal Cost of Losses that would otherwise be applied to the valid and balanced portions of any TOR Self-Schedule in the IFM as provided in Section 11.5.7.2.

* * *

- [Not Used]

* * *

- Schedule

A Day-Ahead Schedule or a FMM Schedule.

*** * ***

- Security Constrained Unit Commitment (SCUC)

An algorithm performed by a computer program over multiple hours that determines the Commitment Status and Day-Ahead Schedules, AS Awards, RUC Awards, Hourly Intertie Block

Schedules, FMM Schedules and Dispatch Instructions for selected resources and minimizes production costs (Start-Up, Minimum Load and Energy Bid Costs in IFM, and RTM; Start-Up, Minimum Load and RUC Availability Bid Costs) while respecting the physical operating characteristics of selected resources and Transmission Constraints.

* * *

- Self-Provided Ancillary Services

A Submission to Self-Provide Ancillary Services in the Day-Ahead Market or Real-Time Market that has been accepted by the CAISO. Acceptance will occur prior to Ancillary Service Bid evaluation in the relevant market and indicates that the CAISO has determined the submission is feasible with regard to resource operating characteristics and regional constraints and is qualified to provide the Ancillary Service in the market for which it was submitted. Self-Provided Ancillary Services consist of self-provided Regulation Up reserves, self-provided Regulation Down reserves, self provided Spinning Reserves, and self-provided Non-Spinning Reserves.

* * *

- Self-Schedule

The Bid component that indicates the quantities in MWhs with no specification of a price that the Scheduling Coordinator is submitting to the CAISO, which indicates that the Scheduling Coordinator is a Price Taker, Regulatory Must-Run Generation or Regulatory Must-Take Generation, which includes ETC and TOR Self-Schedules, Self-Schedules for Converted Rights, and Variable Energy Resource Self-Schedules.

* * *

- Set Point

Scheduled operating level for each Generating Unit or other resource scheduled to run in the FMM Schedule and FMM Award.

* * *

- Settlement Interval

The five-minute time period over which the CAISO settles cost compensation amounts or deviations in Generation and Demand in the RTM.

* * *

- Spinning Reserve Cost

The revenues paid to the suppliers of the total awarded Spinning Reserve capacity in the Day-Ahead Market and Real-Time Market for the Settlement Period, minus the payments rescinded in the Settlement Period due to the unavailability of the Spinning Reserve under any of the provisions of Section 8.10.2.

* * *

- Tolerance Band

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

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

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

* * *

- Uninstructed Imbalance Energy (UIE)

The portion of Imbalance Energy that is not RTD Instructed Imbalance Energy.

* * *

- Variable Energy Resource

A device for the production of electricity that is characterized by an Energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

*** * ***

Appendix C

Locational Marginal Price

* * *

B. The System Marginal Energy Cost Component of LMP

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

the cost of economically providing the next increment of Energy at the distributed Reference Bus, based on submitted Bids.

* * *

Appendix E

Submitted Ancillary Services Data Verification

*** * ***

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

* * *

Appendix G

Pro Forma Reliability Must-Run Contract

MUST-RUN SERVICE AGREEMENT

* * *

DEFINITIONS

*** * ***

"Forced Outage" means a reduction in Availability of a Unit for which sufficient notice is not given to allow the outage to be factored into CAISO's Day-Ahead Market or Real-Time Market.

* * *

Appendix I Station Power Protocol

* * *

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

(a) Imports of Net Output must be submitted in Self-Schedules using a Resource ID specified by the CAISO;

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

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

(d) Meter Data for generating facilities located outside the CAISO Balancing Authority Area shall be subject to CAISO audit to verify performance in accordance with these requirements.

* * *

Appendix L Method To Assess Available Transfer Capability

* * *

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

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

*** * ***

L.1.3 **Existing Transmission Commitments (ETComm)** include Existing Contracts and Transmission Ownership Rights (TOR). The CAISO reserves transmission capacity for each ETC and TOR based on TRTC Instructions the responsible Participating Transmission Owner or Non-Participating Transmission Owner submits to the CAISO as to the amount of firm transmission capacity that should be reserved on each Transmission Interface for each hour of the Trading Day in accordance with Sections 16 and 17 of the CAISO Tariff. The types of TRTC Instructions the CAISO receives generally fall into three basic categories:

- The ETC or TOR reservation is a fixed percentage of the TTC on a line, which decreases as the TTC is derated (ex. TTC = 300 MW, ETC fixed percentage = 2%, ETC = 6 MWs. TTC derated to 200 MWs, ETC = 4 MWs);

- The ETC or TOR reservation is a fixed amount of capacity, which decreases if the line's TTC is derated below the reservation level (ex. ETC = 80 MWs, TTC declines to 60 MW, ETC = TTC or 60 MWs; or

- The ETC or TOR reservation is determined by an algorithm that changes at various levels of TTC for the line (ex. Intertie TTC = 3,000 MWs, when line is operating greater than 2,000 MWs to full capacity ETC = 400 MWs, when capacity is below 2000 MWs ETC = TTC/2000* ETC).

Existing Contract capacity reservations remain reserved during the Day-Ahead Market and through the FMM. To the extent that the reservations are unused after the FMM has been run for

a given fifteen-minute interval, then the capacity reservations are released for the three RTD intervals within that fifteen-minute interval.

Transmissions Ownership Rights capacity reservations remain reserved during the Day-Ahead Market and Real-Time Market. This capacity is under the control of the Non-Participating Transmission Owner and is not released to the CAISO for use in the markets.

L.1.4 ETC Reservations Calculator (ETCC). The ETCC calculates the amount of firm transmission capacity reserved (in MW) for each ETC or TOR on each Transmission Interface for each hour of the Trading Day.

- **CAISO Updates to ETCC Reservations Table.** The CAISO updates the ETC and TOR reservations table (if required) prior to Market Close of the DAM and prior to Market Close of the RTM. The amount of transmission capacity reservation for ETC and TOR rights is determined based on the TTC of each Transmission Interface and in accordance with the curtailment procedures stipulated in the existing agreements and provided to the CAISO by the responsible Participating Transmission Owner or Non-Participating Transmission Owner.

- **Market Notification.** ETC and TOR allocation (MW) information is published for all Scheduling Coordinators which have ETC or TOR scheduling responsibility in advance of the Day-Ahead Market and the Real-Time Market. This information is posted on the Open Access Same-Time Information System (OASIS).

- For further information, see CAISO Operating Procedure M-423, Scheduling of Existing Transmission Contract and Transmission Ownership Rights, which is publicly available on the CAISO Website.

L.1.5 Transmission Reliability Margin (TRM) is an amount of transmission transfer capability reserved at a CAISO Intertie point that is necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

The CAISO uses TRM at Intertie points to account for the following NERC-approved components of uncertainty:

- Forecast uncertainty in transmission system topology, including forced or unplanned outages or maintenance outages.
- Allowances for parallel path (loop flow) impacts, including unscheduled loop flow.
- Allowances for simultaneous path interactions.

The CAISO establishes hourly TRM values for each of the applicable components of uncertainty prior to the Market Close of the RTM. The CAISO does not use TRM (i.e., TRM values for Intertie points are set at zero) during the beyond day-ahead and pre-schedule (i.e., planning) time frame identified in R.1.3.3 of NERC Reliability Standard MOD-008-1. A positive TRM value for a given hour is set only if one or more of the conditions set forth below exists for a particular Intertie point. Where none of these conditions exist, the TRM value for a given hour is set at zero.

The methodology the CAISO uses to establish each component of uncertainty is as follows:

The CAISO uses the transmission system topology component of uncertainty to address a potential ATC path limit reduction at an Intertie resulting from an emerging event, such as an approaching wildfire, that is expected to cause a derate of one or more transmission facilities comprising the ATC path. When the CAISO, based on existing circumstances, forecasts that such a derate is expected to occur, the CAISO may establish a TRM value for the affected ATC path in an amount up to, but no greater than, the amount of the expected derate.

The CAISO uses the parallel path component of uncertainty to address the impact of unscheduled flow (USF) over an ATC path that is expected, in the absence of the TRM, to result in curtailment of Intertie Schedules in Real Time as a result of the requirements established in WECC's applicable USF mitigation policies and procedures (WECC USF Policy). When the CAISO forecasts, based on currently observed USF conditions and projected scheduled flow for an upcoming Operating Hour(s), that in the absence of a TRM, scheduled flow will need to be curtailed in Real Time under the applicable WECC USF Policy, the CAISO may establish a TRM for the ATC path for the applicable hour(s) in an amount up to, but no greater than, the forecasted amount that is expected to be curtailed in Real Time pursuant to the WECC USF Policy.

The CAISO uses the simultaneous path interactions component of uncertainty to address the impact that transmission flows on an ATC path located outside the CAISO's Balancing Authority Area may have on the transmission transfer capability of an ATC path located at an Intertie. In the event of such path interactions, the CAISO uses a TRM value to prevent the risk of a system operating limit violation in Real Time for the CAISO ATC path. The amount of the TRM value may be set at a level up to, but not greater than, the forecasted impact on the CAISO ATC path's capacity imposed by expected flow on the non-CAISO ATC path.

The CAISO uses the following databases or information systems, or their successors, in connection with establishing TRM values: SLIC, Existing Transmission Contract Calculator (ETCC), PI, EMS, and CAS.

*** * ***

L.2 ATC Algorithm

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

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

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

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

ATC Calculation For Internal Paths 15 and 26:
ATC = TTC – CBM – TRM – Net Energy Flow

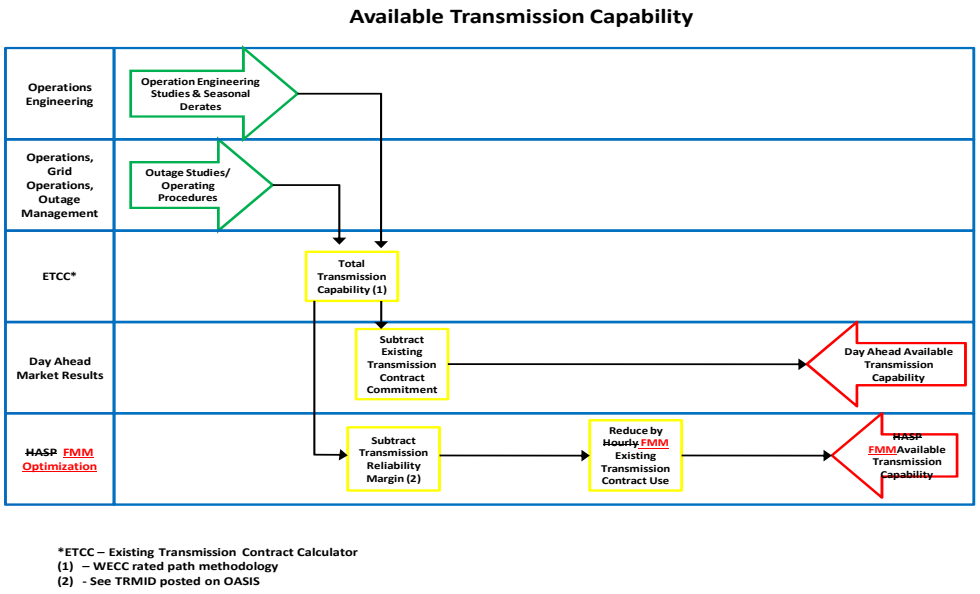
The specific data points used in the ATC calculation are each described in the following table.

ATC	ATC MW	Available Transfer Capability, in MW, per Transmission Interface and path direction.

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

Actual ATC mathematical algorithms and other ATC calculation information are located in the CAISO's ATC Implementation Document (ATCID) posted on OASIS.

L.3 ATC Process Flowchart



* * *

Appendix M

Dynamic Scheduling Protocol (DSP)

1. DYNAMIC SCHEDULES OF IMPORTS TO THE CAISO BALANCING AUTHORITY AREA

*** * ***

1.5.8 If there is no Dynamic Schedule in the CAISO's Day-Ahead Market or RTM, the dynamic signal must be at "zero" ("0") except when in response to CAISO's Dispatch Instructions associated with accepted Ancillary Services or Energy Bids.

*** * ***

1.7.3 All Day-Ahead Market and RTM submitted Dynamic Schedules shall be subject to CAISO Congestion Management and as such may not exceed their transmission reservations in Real-Time (with the exception of intra-hour Dispatch Instructions of the Energy associated with accepted Ancillary Services Bids or Dispatch Instructions for Imbalance Energy).

*** * ***

2.5.6 If there is no Dynamic Schedule in the CAISO's Day-Ahead Market or RTM, the dynamic signal must be at "zero" ("0").

*** * ***

2.6.2 All Day-Ahead Market and RTM submitted Dynamic Schedules shall be subject to CAISO Congestion Management and as such may not exceed their transmission reservations in Real-Time (with the exception of intra-hour Dispatch Instructions for Imbalance Energy issued by the CAISO and responses to the dynamic signal from the Balancing Authority receiving the Dynamic Schedule of the export of Energy).

* * *

Appendix N

Pseudo-Tie Protocol

* * *

1.2.2.3 If there is no Scheduled Generation in the DAM or Real-Time markets, a Pseudo-Tie Generating Unit shall not generate except when issued an Exceptional Dispatch or operating order as defined in Section 37.2.1.1 of the CAISO Tariff from the CAISO.

*** * ***

2.2.3.4 In the event of a line outage and a subsequent request by the Balancing Authority for the Attaining Balancing Authority Area for emergency Wheeling

service from the CAISO to maintain deliveries of power to the Attaining Balancing Authority Area from the Pseudo-Tie generating unit, all CAISO Tariff market and GMC charges applicable to the resulting use of CAISO transmission service shall be applied for the duration of these events, inclusive of any related FMM Schedules.

Appendix Q

Eligible Intermittent Resources Protocol (EIRP)

* * *

2.2.5 Information Requirements For Participating Intermittent Resource Export Fee

In order for the CAISO to administer, implement and calculate the Participating Intermittent Resource Export Fee, each Participating Intermittent Resource jointly with, and through, its Scheduling Coordinator must provide the CAISO with the following information and documents under the schedule and conditions set forth in this section.

The CAISO will maintain the confidentiality of all information and documents received under this section in accordance with CAISO Tariff Section 20 et seq.

A. A certification, in the form set for in a Business Practice Manual, signed by an officer of the Participating Intermittent Resource and its Scheduling Coordinator, identifying (1) the PIR Export Percentage under Section 5.3.2 of this EIRP for resources that have elected PIRP Protective Measures, if any, and basis thereof, and (2) each contract to sell Energy or capacity from the Participating Intermittent Resource, including for each such contract, the counterparty, start and end dates, delivery point(s), quantity in MW, other temporal terms, i.e., seasonal or hourly limitations.

   The certification must be updated by resubmission to the CAISO (1) upon a request to modify the composition of the Participating Intermittent Resource under Section 2.4.2 of this EIRP; or (2) within ten (10) calendar days of final execution of a new contract or any change in counterparty, start and end dates, delivery point(s), quantity in MW, or other temporal terms, as described above, for any prior certified contract. All other contractual changes will not trigger the obligation for recertification.

B. Copies of all contracts, including changes, identified in the above-referenced certification; however, price information may be redacted from the contracts provided.

Each Participating Intermittent Resource, as of November 1, 2006, must initially provide the information requested by this Section 2.2.5 in accordance with a Market Notice provided by the CAISO to Participating Intermittent Resources. All other Eligible Intermittent Resources must satisfy this Section 2.2.5 in order to become a Participating Intermittent Resource after November 1, 2006.

*** * ***

4.1 [Not Used]

*** * ***

5 SCHEDULING AND SETTLEMENT

5.1 Schedules

For all Generating Units that comprise the Participating Intermittent Resources shall comply with the Bidding and scheduling rules specified in Sections 4.8, 30, 31, and 34.

*** * ***

5.3 Participating Intermittent Resource Export Fee

The rules specified in this Section 5.3 and its subsection applies only to Participating Intermittent Resources that have elected PIRP Protective Measures and do not apply to resources that have not elected for such measures.

5.3.3 Monthly Application of Participating Intermittent Resource Export Fee

Each month the CAISO will charge Exporting Participating Intermittent Resources the

Participating Intermittent Resource Export Fee, as set forth in Schedule 4 of Appendix F.

Attachment B – Marked Tariff Sheets

Real-Time Market Design Enhancements Related to Order No. 764

California Independent System Operator Corporation

November 26, 2013

4.5.3.12 Financial Responsibility

Assuming financial responsibility for all Schedules, ~~awards, HASP Intertie Schedules~~AS Awards, and Dispatch Instructions issued in the CAISO Markets, and all Virtual ~~Bids~~Awards in accordance with the provisions of this CAISO Tariff; and

* * *

4.8 Relationships Between CAISO And Intermittent Resources

4.8.1 Bidding and Settlement

The CAISO shall not accept Bids for an Eligible Intermittent Resource other than through a Scheduling Coordinator. Any Eligible Intermittent Resource that is not a Participating Intermittent Resource, or any Participating Intermittent Resource for which Bids are submitted shall be bid and settled as a Generating Unit for the associated Settlement Periods (except that the Forecast Fee shall apply in such Settlement Periods). Scheduling Coordinators shall not submit Economic Bids for Participating Intermittent Resources that are subject to PIRP Protective Measures.

4.8.2 Forecasting

All Scheduling Coordinators for Eligible Intermittent Resources are subject to the forecasting requirements and the Forecast Fee as described below. All Eligible Intermittent Resources must provide the CAISO meteorological and outage data as specified in Appendix Q. Scheduling Coordinators for Variable Energy Resources not located in the CAISO Balancing Authority Area that elect to use the forecast provided by the CAISO are also subject to the Forecast Fee.

4.8.2.1 Forecast Requirements

4.8.2.1.1 Use of Own Forecast

For purposes of participating in the CAISO Markets, Eligible Intermittent Resource may opt to use their own forecast of their resource's output, and not use the forecast of their output provided by the CAISO, only to the extent the CAISO has certified that the Eligible Intermittent Resource has completed the certification requirements specified in the Business Practice Manuals. If the Eligible Intermittent Resources is certified to provide their own forecast, they must provide at a minimum a three-hour rolling forecast with fifteen- (15) minute granularity, updated every fifteen minutes, and may provide in the alternative a three-hour rolling forecast at five- (5) minute

granularity, updated every five minutes. If an Eligible Intermittent Resource opts to provide the forecast of their output at a five-minute granularity, the CAISO will use the average of the projected Energy output for the relevant three five (5)-minute forecasts to determine the Variable Energy Resource Self-Schedule for the Fifteen Minute Market as specified in Section 34. An Eligible Intermittent Resource that has elected to use its own forecast of its output must also submit the meteorological and outage data specified in Appendix Q. After the CAISO has certified an Eligible Intermittent Resource as eligible to provide its own output forecast, the CAISO may terminate the resource's certification if the CAISO determines that: (1) the Eligible Intermittent Resource's forecast is materially less accurate than the forecast provided by the CAISO on a regular basis; or (2) if the CAISO has a reasonable basis to believe that the resource is engaged in strategic forecasting for purposes other than accuracy. If the CAISO revokes the certification of an Eligible Intermittent Resource to use its own forecast, the Eligible Intermittent Resource must again complete the certification requirements specified in the Business Practice Manuals before it can again qualify to use its own forecast. For purposes of participating in the CAISO Markets, Participating Intermittent Resources may opt to use their own output forecast if they are certified to do so by the CAISO pursuant to the rules specified in the Business Practice Manuals, in which case: (1) the resource will retain its status as a Participating Intermittent Resource; (2) the CAISO will not submit the updated output forecast for that resource through the Real-Time Market; and (3) the resource will be subject to the same requirements that apply to Eligible Intermittent Resource that use their own output forecast as specified in the CAISO Tariff. Participating Intermittent Resources that are subject to PIRP Protective Measures are not eligible to opt to use a forecast of their output for purposes of participating in the CAISO Markets other than the forecast of their output provided by the CAISO.

4.8.2.1.2 Use of Forecast from Independent Forecast Provider

For purposes of participating in the CAISO Markets, Eligible Intermittent Resources have the option to use a forecast of their output provided by CAISO. Variable Energy Resources that are located outside the CAISO Balancing Authority Area may also elect to use the output forecast provided by the CAISO, provided that: (1) they agree to provide the CAISO with the

meteorological data specified in Appendix Q; and (2) they are certified to do so by the CAISO pursuant to the rules specified in the Business Practice Manuals. Once the election to use the output forecast provided by the CAISO is complete, the CAISO will specify the election status for the Eligible Intermittent Resource or the external Variable Energy Resource in the Master File. The Eligible Intermittent Resource and any Variable Energy Resource located outside of the CAISO Balancing Authority Area opting to use the forecast of their output provided by the CAISO, must provide the meteorological and outage data as specified in Appendix Q. Any changes to this election will be subject to the timeline and rule changes that apply to the Master File as specified in Section 30.7.3.2.

4.8.2.2 Application of the Forecast Fee

All Eligible Intermittent Resources are subject to the forecast fee specified in Section 2.4.1 of Appendix Q, regardless of whether the resource elects to use the CAISO-created forecast or relies on its own forecast. Variable Energy Resources located outside the CAISO Balancing Authority Area that elect to use the forecast of their output provided by the CAISO are also subject to the Forecast Fee specified in Section 2.4.1 of Appendix Q.

4.8.3 PIRP Protective Measures

4.8.3.1 Request for PIRP Protective Measures

4.8.3.1.1 Timing

Participating Intermittent Resources or Qualifying Facilities that wish to qualify for PIRP Protective Measures pursuant to Section 4.8.3.2 within the three-year transition period must complete their election for PIRP Protective Measures no later than thirty (30) days after the effective date of this Section 4.8.3.

4.8.3.1.2 Materials Submitted with Request

For a resource to qualify for PIRP Protective Measures, within thirty (30) days from the effective date of this Section, responsible parties must submit affidavits as described in either Section 4.8.3.1.2.1 or Section 4.8.3.1.2.2. The CAISO reserves the right to audit the representations made in the affidavits by giving written notice at least ten (10) Business Days in advance of the date that the CAISO wishes to initiate such audit, with completion of the audit occurring within 60

days of such notice. The audit shall be for the limited purposes of verifying that the Participating Intermittent Resource and counterparty to the relevant contract has represented the terms specified in the affidavit accurately. Upon request of the CAISO as part of such audit, the Participating Intermittent Resource or counterparty providing the affidavits specified below shall provide information to support its certification under Sections 4.8.3.1.2.1 or Section 4.8.3.1.2.2, as appropriate. Each party will be responsible for its own expenses related to any audit.

4.8.3.1.2.1 Physical Limitations

A Participating Intermittent Resource or Qualifying Facility requesting PIRP Protective Measures because of physical limitations, as specified in Section 4.8.3.2.2.1, must submit a sworn affidavit by a representative of the Participating Intermittent Resource or Qualifying Facility, who is authorized to bind the resource legally and financially . The affidavit must state that the resource meets the criteria specified in Section 4.8.3.2.1 and 4.8.3.2.2.1. The sworn affidavit must also state that the relevant party agrees that during the term of the three-year transition period, the party will engage in a good faith effort to upgrade the facility in order to address the limitations specified in Section 4.8.3.2.2.1.

4.8.3.1.2.2 Contractual Limitations

A Participating Intermittent Resource or Qualifying Facility requesting PIRP Protective Measures because of contractual limitations as specified in Section 4.8.3.2.2.2, must submit a sworn affidavit by a representative of the Participating Intermittent Resource or Qualifying Facility, who that is authorized to bind the resource legally and financially. The affidavit must state that the resource is subject to a contract that meets the criteria specified in Sections 4.8.3.2.1 and 4.8.3.2.2.2. The Participating Intermittent Resource or Qualifying Facility must serve their affidavit electronically to the counterparty to the applicable contract on the same day the affidavit is submitted to the CAISO. A representative of the counterparty to the applicable existing bilateral agreement that is authorized to legally and financially bind the counterparty may also submit a sworn affidavit stating that the resource is subject to a contract that meets the criteria specified in Sections 4.8.3.2.1 and 4.8.3.2.2.2. The counterparty must serve the affidavit electronically on the Participating Intermittent Resource or Qualifying Facility on the same day the

affidavit is submitted to the CAISO. Each party's respective affidavit must state that during the term of the three-year transition period, the party will engage in a good faith effort with the counterparty to address the existing contractual limitation specified in Section 4.8.3.2.2.2. In the event that the counterparty submits no affidavits within the thirty days, the CAISO deems the counterparty to have acquiesced to the request by the representative of the Participating Intermittent Resource, except if the Participating Intermittent Resource fails to serve the counterparty with the required documents within the prescribed time. If the counterparty later successfully demonstrates through a formal complaint filed at the Federal Energy Regulatory Commission that the Participating Intermittent Resource failed to serve the counterparty with the relevant materials as described in this Section, the CAISO will deny, and if appropriate reverse, any PIRP Protective Measures afforded to the requesting party. To the extent that the counterparty instead submits an affidavit by a representative of the company that is fully authorized to legally and financially bind the company stating that the resource's contract does not meet the criteria in Sections 4.8.3.2.1 and 4.8.3.2.2.2, the affidavit must also state that the Participating Intermittent Resource shall not suffer any economic or other repercussions under the contract and because of the terms of the contract were the resource to participate fully in the CAISO Market, including through the submission of Economic Bid for economic curtailment. The representative of the Participating Intermittent Resource may choose to withdraw its request in light of the counterparty's affidavit or pursue resolution of a contractual dispute through a dispute resolution process specified in the relevant contract, or if none is available, through the process specified in Section 13 of the CAISO Tariff, or through any dispute resolution process available through the Federal Energy Regulatory Commission. During the term that the contract is in dispute, the resource will be subject to PIRP Protective Measures provided it meets all the other criteria specified in this Section 4.8.3. Upon resolution of the dispute, if the dispute resolution process yields a conclusion that the contract is not eligible for PIRP Protective Measures, the resource will resume its status as a Participating Intermittent Resource not subject to PIRP Protective Measures. Unless, the parties together request the CAISO to reverse any previously

applied PIRP Protective Measures, the CAISO will not undo any prior Settlement of the PIRP Protective Measures.

4.8.3.2 Criteria

Participating Intermittent Resources or Qualifying Facilities that are registered as such on the day that this Section 4.8.3 becomes effective may qualify for PIRP Protective Measures if they meet the criteria specified below. Fulfilling such criteria is a requirement in addition to providing the affidavits described in Section 4.8.3.1.2. Qualifying Facilities whose capacity exceeds twenty (20) MW on the day this tariff section becomes effective may qualify if they meet the criteria specified below. Such Qualifying Facilities that elect and qualify for PIRP Protective Measures must also be qualified as a Participating Intermittent Resource for the term over which they are to receive the PIRP Protective Measures.

4.8.3.2.1 Exposure to Real-Time Imbalance Energy

The Participating Intermittent Resource, or Qualifying Facility upon expiration of its Qualifying Facility contract with a Utility Distribution Company, either: (1) is subject to an existing bilateral agreement for power purchases from the affected resource, such as a power purchase agreement, that is in effect the day this Section becomes effective, and such agreement in its totality requires that the resource owner directly or indirectly is subject to Real-Time Imbalance Energy Settlement in the CAISO Market; or (2) is not subject to any bilateral agreement for power purchases from the affected resource on the day this section becomes effective and, therefore, the resource is itself subject to Real-Time Imbalance Energy Settlement in the CAISO Market.

4.8.3.2.2 Ability to Curtail

The affected resource must also meet one of the two criteria below:

4.8.3.2.2.1 Physical Limitation

More than fifty (50) percent of the Participating Intermittent Resource or Qualifying Facility is composed of technology that is unable to curtail output and cannot be made to do so without significant investment. Participating Intermittent Resources that only lack Dispatch, control, and telemetry or metering that require upgrades to be able to respond will not qualify. Participating

Intermittent Resources that require production facility investments, such as turbine replacements, will qualify.

4.8.3.2.2.2 Contractual Limitation

The resource is subject to an existing bilateral agreement for power purchases, such as a power purchase agreement, that is in effect on the date on which this Section become effective, and that prohibits the resource from curtailing its output (not including times when they are ordered to do so by the CAISO or an affected Utility Distribution Company for reliability reasons).

4.8.3.3 Term of PIRP Protective Measures

The PIRP Protective Measures for a specific Participating Intermittent Resource shall be in effect until the earlier date of (1) three years after the effective date of this Section, or (2) the execution between the Participating Intermittent Resource owner and its counterparty of a new or amended power purchase agreement (or similar contract for services) that addresses their Imbalance Energy settlement.

4.8.3.4 Posting

The CAISO will post on its Website the names of the Participating Intermittent Resources that have elected, and subsequently been qualified, to receive PIRP Protective Measures.

* * *

4.9.5.2 The Scheduling Coordinator for the MSS will designate, in discrete quantities and with prices for both Ancillary Services and Energy: (1) Bids in the Day-Ahead Market and ~~HASP~~Real-Time Market (including Bids for internal Generation and internal Demand within the MSS), (2) Submissions to Self-Provide Ancillary Services or Bids for Regulation, Spinning Reserve, and Non-Spinning Reserve, capacity and associated Bid for Energy, or (3) any feasible combination thereof.

* * *

6.5.4 ~~HASP~~RTM Communications Before The Trading Hour

The ~~HASP opens~~RTM is intended to open at 1:00 p.m. the day before the target Operating Day ~~and~~to coincide with the posting of results from the DAM, which may be delayed for reasons

specified in Section 31.6. Scheduling Coordinators can submit Bids into the ~~HASP~~RTM as of ~~that~~the time such results are posted.

6.5.4.1 Communications With Scheduling Coordinators

6.5.4.1.1 Before one hundred thirty-five (135) minutes before the Trading Hour, the CAISO will continuously screen Inter-SC Trades of Energy for the ~~HASP~~RTM, Inter-SC Trades of Ancillary Services, and Inter-SC Trades of IFM Load Uplift Obligations submitted by Scheduling Coordinators and will communicate with the Scheduling Coordinators about the consistency and validity of these Inter-SC Trades based on information available to the CAISO.

6.5.4.1.2 Between one hundred thirty-five (135) minutes before the Trading Hour and forty-five (45) minutes before the Trading Hour, the CAISO will perform the pre-market validation check for Inter-SC Trades for the ~~HASP~~RTM and Inter-SC Trades of Ancillary Services and will provide feedback to the Scheduling Coordinators about the validity of these Inter-SC Trades based on information available to the CAISO.

* * *

6.5.4.1.5 No later than forty ~~(40~~ five (45) minutes before the Trading Hour, on an hourly basis, the CAISO will publish via the secure communication system ~~the following:~~results of the HASP processes.

~~(a) HASP Intertie Schedules and LMPs; and~~

~~(b) HASP AS Awards and ASMPs~~

* * *

6.5.4.1.6 [Not Used] ~~No later than thirty (30) minutes before the Trading Hour, on an hourly basis, the CAISO will publish via the secure communication system the following:~~

~~(a) HASP Advisory Schedules;~~

~~(b) HASP AS Awards; and~~

~~(c) HASP final resource Bid mitigation results.~~

* * *

6.5.4.2.1 By one hundred five (105) minutes before the Trading Hour the CAISO will publish information regarding Outages on the transmission system on OASIS that will be used for ~~HASP~~

~~Schedules and~~ Congestion Management, HASP Block Intertie Schedules and HASP Advisory Schedules that involve an Intertie transaction.

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

(a) Total HASP Block Intertie Schedules and HASP Advisory Schedules that involve an Intertie transaction for imports and exports by TAC Area and for the entire CAISO Balancing Authority Area;

(b) HASP ~~Intertie LMPs by PNodes and APNodes;~~

~~(c) HASP~~ advisory LMPs by PNode and APNode;

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

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

6.5.5 Real-Time Market Communications During the Trading Hour

The CAISO shall issue Dispatch Instructions to Scheduling Coordinators determined pursuant to the RTM throughout any given day.

* * *

6.5.5.2.2 Every fifteen (15) minutes the CAISO shall post via OASIS information regarding the status of the RTM. ~~-~~This information shall include but is not limited to the following:

(a) ~~——~~Total Real-Time AS Awards by AS Region and AS type~~; and~~

(b) ~~——~~Real-Time ASMPs by AS Region and AS type~~.~~; and

(c) FMM LMP.

* * *

7.6.1 Actions For Maintaining Reliability Of CAISO Controlled Grid

The CAISO shall obtain the control over Generating Units that it needs to control the CAISO Controlled Grid and maintain reliability by ensuring that sufficient Energy and Ancillary Services are procured through the CAISO Markets. ~~-~~When the CAISO responds to events or circumstances, it shall first use the generation control it is able to obtain from the Energy and Ancillary Services Bids it has received to respond to the operating event and maintain reliability. Only when the CAISO has used the Energy and Ancillary Services that are available to it under such Energy and Ancillary Services Bids which prove to be effective in responding to the problem and the CAISO is still in need of additional control over Generating Units, shall the CAISO assume supervisory control over other Generating Units. ~~-~~It is expected that at this point, the operational circumstances will be so severe that a Real-Time system problem or emergency condition could be in existence or imminent.

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

(a) compliance with Dispatch Instructions including instructions to deliver Energy and Ancillary Services in Real-Time pursuant to the AS Awards, Day-Ahead Schedules and ~~HASP Intertie~~FMM Schedules, and ~~HASP~~FMM AS Awards;

(b) ~~——~~ ___compliance with the system operation requirements set out in this Section 7;

(c) notification to the CAISO of the persons to whom an instruction of the CAISO should be directed on a 24-hour basis, including their telephone and facsimile numbers; and

(d) the provision of communications, telemetry and direct control requirements, including the establishment of a direct communication link from the control room of the Generator to the CAISO in a manner that ensures that the CAISO will have the ability, consistent with this CAISO

Tariff, to direct the operations of the Generator as necessary to maintain the reliability of the CAISO Controlled Grid, except that a Participating Generator will be exempt from CAISO requirements imposed in accordance with this subsection (d) with regard to any Generating Unit with a rated capacity of less than ten (10) MW, unless that Generating Unit is certified by the CAISO to provide Ancillary Services.

7.7 Management Of System Emergencies

7.7.1 System Emergency

When, in the judgment of the CAISO, the System Reliability of the CAISO Controlled Grid is in danger of instability, voltage collapse or under-frequency caused by transmission or Generation trouble in the CAISO Balancing Authority Area, or events outside of the CAISO Balancing Authority Area that could result in a cascade of events throughout the WECC grid, the CAISO will declare a System Emergency. -This declaration may include a notice to suspend the Day-Ahead ~~Market, HASP~~ and Real-Time Markets, authorize full use of Black Start Generating Units, initiate full control of manual Load Shedding, and authorize the curtailment of Curtailable Demand (even though not scheduled as an Ancillary Service).- The CAISO will reduce the System Emergency declaration to a lower alert status when it is satisfied, after conferring with Reliability Coordinators within the WECC, that the major contributing factors have been corrected, and all involuntarily interrupted Demand is back in service (except interrupted Curtailable Demand selected as an Ancillary Service). -This reduction in alert status will reinstate the competitive markets if they have been suspended.

* * *

7.7.3.2 System Warning

The CAISO will give an AWE Notice of a system warning when the operating requirements for the CAISO Controlled Grid are not being met in the ~~HASP or~~ Real-Time Market, or the quantity of Regulation, Spinning Reserve, Non-Spinning Reserve, and Energy available to the CAISO is not acceptable for the Applicable Reliability Criteria.- This system warning notice will notify Market Participants that the CAISO will, acting in accordance with Good Utility Practice, take such steps

as it considers necessary to ensure compliance with Applicable Reliability Criteria, including the negotiation of commitments for Generation through processes other than competitive Bids.

* * *

7.7.11.4.2 If the CAISO forecasts in advance of the ~~HASP~~RTM that Load curtailment will be necessary due to a resource deficiency as determined pursuant to Section 40.7, the CAISO will identify any UDC or MSS Service Area that is resource deficient.~~-~~ The CAISO will provide notice to all Scheduling Coordinators if one or more UDC or MSS is deficient. ~~-~~If Load curtailment is required to manage a System Emergency associated with a resource deficiency determined pursuant to Section 40.7, the CAISO will determine the amount and location of Load to be curtailed and will allocate a portion of that required Load curtailment to each UDC or MSS Operator whose Service Area has been identified as being resource-deficient based on the ratio of its resource deficiency to the total Balancing Authority Area resource deficiency. ~~-~~Each UDC or MSS Operator shall be responsible for notifying its customers and Generators connected to its system of curtailments and service interruptions.

* * *

7.7.14.2.2 Communications during Unavailability of CAISO's Secure Communication System

During any period of CAISO's secure communication system unavailability, the CAISO shall:

(a) make all reasonable efforts to keep Market Participants aware of current CAISO Controlled Grid status using voice communications;

(b) use the most recent set of Day-Ahead Schedules, RUC Schedules, AS Awards, ~~HASP Intertie~~FMM Schedules, and Dispatch Instructions for each Scheduling Coordinator for the current and all future Settlement Periods and/or Trading Days until the CAISO's secure communication system is restored; and

(c) attempt to take critical Bids, including ETC and TOR Self-Schedules changes, from Scheduling Coordinators via voice communications as time and personnel availability allows.

* * *

7.7.15.2.2 Consequences of Removal of a Bid

The CAISO may remove part of a Bid, but retain other parts of the Bid for the applicable CAISO Market run and interval for the same or different product, and may retain parts of the Bid for subsequent CAISO Market runs or intervals. ~~-~~If a particular Energy or Ancillary Service Bid must be removed pursuant to Section 7.7.15.2.1, the CAISO will remove the entire Bid for that particular service and market. ~~-~~The Scheduling Coordinator may resubmit removed Bids in subsequent CAISO Markets, provided the Scheduling Coordinator complies with any operator instructions regarding the subject Bids. ~~-~~In the event a Bid is removed from an IFM run, the RUC Availability Bid associated with the removed IFM Bid may still be accepted for the corresponding RUC run, unless the RUC Availability Bid is determined to be the cause of the disruption. A problematic Bid as described in Section 7.7.15.2.1 will typically be identified as infeasible prior to publication of the CAISO Market interval in which it is causing a problem, in which case to the extent practicable the CAISO may remove the Bid, execute the CAISO Market without the removed Bid, and publish a CAISO Market result for that interval. ~~-~~In some instances, a Bid may be able to clear through the IFM without causing an infeasibility issue, but then it may be necessary to remove the RUC Availability Bid associated with the IFM Bid for the corresponding RUC run due to infeasibility issues raised for the RUC run. In the Real-Time Market, for ~~example, for~~ reasons discussed above, the CAISO may also be required to remove a Bid for a Non-Dynamic System Resource that ~~would~~ normally would be ~~dispatched~~accepted in the HASP, yet may be able to utilize and accept the ~~Bids submitted~~Bid for the RTD and non-HASP RTUC runs of the Real-Time Market included within the same Scheduling Coordinator Bid submission. If, for the reasons discussed above, the CAISO is required to remove a Bid in the advisory RTUC or RTD runs conducted for future intervals during the Real-Time Market, the removed Bid may still be used in the binding runs of the Real-Time Market for the same interval if the problems

previously experienced with the Bid do not arise. If an Ancillary Service Bid or Submission to Self-Provide Ancillary Services is removed from the IFM, the Scheduling Coordinator may resubmit these components in the RTM provided the issues identified in the IFM have been resolved and the Bid or submission is otherwise consistent with the Ancillary Service bidding rules in the CAISO Tariff.

If the CAISO is required to remove an Ancillary Services Bid submitted ~~in~~to the Real-Time Market ~~for consideration in the RTUC run~~, the CAISO may retain the Energy Bid submitted in association with the Ancillary Services Bid for that CAISO Market run.

7.7.15.2.3 Settlement Consequences of Removal of Bids

In the event that a Bid is removed from the Day-Ahead Market, the Scheduling Coordinator whose Bid is removed will not be subject to Settlement for the Day-Ahead Market for the affected service. The Scheduling Coordinator may then resubmit the Bid in the ~~HASP/~~Real-Time Market for the same service and, to the extent the Bid is feasible and the issues identified have been resolved, it may be accepted in the Real-Time Market consistent with the CAISO Tariff requirements that apply to the ~~HASP/~~Real-Time Market. ~~-~~ In the case of Ancillary Services Bids, including Submissions to Self-Provide an Ancillary Service, that are removed from the Day-Ahead Market, the Scheduling Coordinator will not receive Settlement for the Ancillary Services in the Day-Ahead Market and will not receive an opportunity cost payment in the Day-Ahead Market for the offered service. ~~-~~If the Bid is accepted in the ~~HASP/~~Real-Time Market, the Scheduling Coordinator will be subject to Settlement based on the CAISO Market in which the Bid actually clears. ~~-~~ In the event that a Bid is removed from a CAISO Market run or interval, the CAISO may subsequently be required to issue an Exceptional Dispatch for the resource, in which case the Scheduling Coordinator will receive Exceptional Dispatch Settlement as provided in Section 11.5.6. ~~-~~In the event that a Demand Bid is removed from the Day-Ahead Market, because no Demand Bids for load can be submitted in the Real-Time Market, Scheduling Coordinators for the load not cleared in the Day-Ahead Market will be settled as Uninstructed Imbalance Energy as provided in Section 11.5.2.

* * *

8. Ancillary Services

8.1 Scope

The CAISO shall be responsible for ensuring that there are sufficient Ancillary Services available to maintain the reliability of the CAISO Controlled Grid consistent with NERC and WECC reliability standards and any requirements of the NRC. The CAISO's Ancillary Services requirements may be self-provided by Scheduling Coordinators as further provided in the Business Practice Manuals. Those Ancillary Services which the CAISO requires to be available but which are not being self-provided will be competitively procured by the CAISO from Scheduling Coordinators in the Day-Ahead ~~Market, the HASP,~~ and ~~the RTM~~Real-Time Markets consistent with Section 8.3. The provision of Ancillary Services from the Interties with interconnected Balancing Authority Areas is limited to Ancillary Services bid into the competitive procurement processes in the IFM ~~, HASP,~~ and RTM. The CAISO will not accept Submissions to Self-Provide Ancillary Services that are imports to the CAISO Balancing Authority Area over the Interties with interconnected Balancing Authority Areas, except from Dynamic System Resources certified to provide Ancillary Services or if provided pursuant to ETCs, TORs or Converted Rights. The CAISO will accept Submissions to Self-Provide Ancillary Services from Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area if they are certified to provide Ancillary Services. The CAISO will calculate payments for Ancillary Services supplied by Scheduling Coordinators and charge the cost of Ancillary Services to Scheduling Coordinators based on their Ancillary Service Obligations.

For purposes of this CAISO Tariff, Ancillary Services are: (i) Regulation Up and Regulation Down, (ii) Spinning Reserve, (iii) Non-Spinning Reserve, (iv) Voltage Support, and (v) Black Start capability.

These services will be procured as stated in Section 8.3.5. Bids for these services may be submitted by a Scheduling Coordinator for resources that are capable of providing the specific service and that meet applicable Ancillary Service standards and technical requirements, as set forth in Sections 8.1 through 8.4, and are certified by the CAISO to provide Ancillary Services. Identification of specific services in this CAISO Tariff shall not preclude development of additional

interconnected operation services over time. The CAISO and Market Participants will seek to develop additional categories of these unbundled services over time as the operation of the CAISO Controlled Grid matures or as required by regulatory authorities.

* * *

8.2.3.1 Regulation Service

The CAISO shall maintain sufficient resources immediately responsive to the CAISO's EMS control in order to provide sufficient Regulation service to allow the CAISO Balancing Authority Area to meet NERC and WECC reliability standards and any requirements of the NRC by continuously balancing resources to meet deviations between actual and scheduled Demand and to maintain Interchange Schedules. The quantity of Regulation Down and Regulation Up capacity needed for each Settlement Period of the Day-Ahead Market and in each fifteen (15) minute period in Real-Time shall be determined by the CAISO as a percentage of the applicable CAISO Forecast ~~of~~Of CAISO Demand for the Day-Ahead and Real-Time Markets. In HASP, the amount of advisory Regulation from Dynamic System Resources required for each Settlement Period in the next Trading Hour is also determined based on the CAISO Forecast ~~of~~Of CAISO Demand. The advisory awards of Regulation from Dynamic System Resources in HASP are not binding and are re-optimized through the ~~RTUC~~FMM and RTD processes in the Real-Time Market. The CAISO's determination is based upon its need to meet the NERC and WECC reliability standards and any requirements of the NRC.

The requirement for Regulation Down or Regulation Up needed for each Settlement Period of the Day-Ahead Market and in each fifteen (15) minute period in Real-Time shall each be accompanied by a requirement for Mileage as determined by the CAISO. The CAISO shall determine the Mileage requirements in any Settlement Period based on Regulation capacity requirements as well as the Bid-in Regulation capacity for that Settlement Period. Subject to operator adjustment, the Mileage requirement for either Regulation Up or Regulation Down will reflect the minimum of (a) the product of the respective Regulation capacity requirement and the System Mileage Multiplier; (b) the average Instructed Mileage for the applicable Trading Hour

from the prior seven (7) days; or (c) the product of each resource's resource specific Mileage multiplier(s) and its Bid-in Regulation capacity summed for all resources.

The CAISO will publish on OASIS the estimated quantity, or the percentage used to determine the estimated quantity, of Regulation Reserves required for each hour of the Day-Ahead Market and in each fifteen (15) minute period in Real-Time for the Trading Day. The CAISO will publish on OASIS the Mileage requirements for each hour of the Day-Ahead Market and each fifteen (15) minute period in Real-Time for the Trading Day. The CAISO will also publish on OASIS the average Instructed Mileage from the prior seven (7) days for each hour of a Trading Day no later than seven (7) calendar days after the applicable Trading Day.

* * *

8.3 Procurement; Certification And Testing; Contracting Period

8.3.1 Procurement Of Ancillary Services

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

to an ETC, TOR or Converted Right. The amount of additional Ancillary Services procured in the ~~HASP~~RTM is based on the CAISO Forecast ~~of~~Of CAISO Demand, the Day-Ahead Schedules established net interchange, and the forecast of the Intertie Schedules for the Operating Hour in the ~~HASP~~RTM net of (i) available awarded Day-Ahead Ancillary Services, (ii) Self-Provided Ancillary Services from resources internal to the CAISO Balancing Authority Area (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area) and Dynamic System Resources certified to provide Ancillary Services, and (iii) Ancillary Services self-provided pursuant to an ETC, TOR or Converted Right. The amount of Ancillary Services procured in the Real-Time Market is based upon the CAISO Forecast ~~of~~Of CAISO Demand and the ~~HASP Intertie Schedule established~~ net interchange for the Operating Hour from FMM Schedules net of (i) available awarded Day-Ahead Ancillary Services, (ii) Self-Provided Ancillary Services from resources internal to the CAISO Balancing Authority Area (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area) and Dynamic System Resources certified to provide Ancillary Services, (iii) additional Operating Reserves procured in ~~HASP~~the FMM, and (iv) Ancillary Services self-provided pursuant to an ETC, TOR or Converted Right. The CAISO may procure incremental Ancillary Services in the Real-Time Market based in part on a determination during the ~~Hour-Ahead Scheduling Process or Real-Time Unit Commitment~~FMM that any Ancillary Services capacity awarded or self-provided in the Day-Ahead Market is not available as a result of a resource constraint or Transmission Constraints. Resource constraints may include but are not limited to an Outage of a resource or Ramp Rate constraints. Incremental procurement in the Real-Time Market will exclude Ancillary Services Capacity the CAISO has determined is not available.

The CAISO will manage the Energy from both CAISO~~-~~-procured and Self-Provided Ancillary Services as part of the FMM and Real-Time Dispatch. In the Day-Ahead Market, the CAISO procures one-hundred (100) percent of its Ancillary Service requirements based on the Day-Ahead Demand Forecast net of Self-Provided Ancillary Services. After the Day-Ahead Market, the CAISO procures additional Ancillary Services needed to meet system requirements from all resources in the Real-Time Market. The amount of Ancillary Services procured in the ~~HASP and~~

Real-Time Market is based on the CAISO Forecast ~~of~~Of CAISO Demand for the Operating Hour net of Self-Provided Ancillary Services.

~~The CAISO procurement~~Awards of ~~Ancillary Services from~~AS in the RTM to Non-Dynamic System Resources ~~in the HASP is~~are for the entire next Operating Hour. The CAISO procurement of Ancillary Services from all other resources in the Real-Time Market is for a fifteen (15) minute ~~time period to which the relevant RTUC applies.~~FMM interval. The CAISO's procurement of Ancillary Services from Non-Dynamic System Resources ~~in HASP and from~~, Dynamic System Resources and internal Generation (which includes Generation from Generating Units that are Pseudo-Ties to the CAISO Balancing Authority Area) in the Real-Time Market is based on the Ancillary Service Bids submitted or generated in the ~~HASP~~RTM consistent with the requirements in Section 30. The CAISO may also procure Ancillary Services pursuant to the requirements in Section 42.1 and as permitted under the terms and conditions of a Reliability Must-Run Contract.

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

8.3.2 Procurement from Internal And External Resources

The CAISO will procure Spinning Reserves and Non-Spinning Reserves from resources operating within the CAISO Balancing Authority Area (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area) and from imports of System Resources. Scheduling Coordinators are allowed to bid Regulation from resources located outside the CAISO Balancing Authority Area by dynamically scheduling such System Resources certified to provide Regulation. Each System Resource used to bid Regulation must comply with the Dynamic Scheduling Protocol in Appendix M. Scheduling Coordinators may submit Bids for Operating Reserves from Non-Dynamic System Resources but they may not submit Bids for Regulation from such resources because these resources cannot be dynamically scheduled consistent with

Appendix M. When bidding to supply Ancillary Services in the IFM~~, HASP,~~ or RTM, imports and Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area compete for use of Intertie transmission capacity when the requested use is in the same direction, e.g., imports of Ancillary Services and Ancillary Services from Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area compete with Energy on Interties in the import direction, and exports of Ancillary Services (i.e., on demand obligations) compete with Energy on Interties in the export direction. To the extent there is Congestion, imports of Ancillary Services and suppliers of Ancillary Services from Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area will pay Congestion costs in the IFM~~, HASP,~~ and RTM markets pursuant to Section 11.10.1.2.1.

* * *

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

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

8.3.3.3 Notice to Market Participants

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

* * *

8.3.5 Daily And Hourly Procurement

The CAISO shall procure Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve on a daily and Real-Time basis in the IFM and RTM, respectively. ~~The CAISO shall also procure Spinning and Non-Spinning Reserves on an hourly basis in the HASP.~~ The CAISO shall procure Ancillary Services on a longer-term basis pursuant to Section 42.1.3 if necessary to meet Reliability Criteria. The CAISO shall contract for Voltage Support annually (or for such other period as the CAISO may determine is economically advantageous) and on a daily or hourly basis as required to maintain System Reliability. The CAISO shall contract annually (or for such other period as the CAISO may determine is economically advantageous) for Black Start Generation.

* * *

8.3.7 AS Bidding Requirements

Scheduling Coordinators may submit Bids or Submissions to Self-Provide an Ancillary Service consistent with the rules specified in Section 30 and any further requirements in this Section 8.3.7. Scheduling Coordinators may (i) submit Bids or Submissions to Self-Provide an Ancillary Service from resources located within the CAISO Balancing Authority Area (which includes

Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area) or Dynamic System Resources certified to provide Ancillary Services, (ii) submit Submissions to Self-Provide an Ancillary Service from System Resources located outside the CAISO Balancing Authority Area if provided pursuant to ETCs, TORs, or Converted Rights, (iii) submit Bids for Ancillary Services from Dynamic and Non-Dynamic System Resources located outside the CAISO Balancing Authority Area certified to provide Ancillary Services, or (iv) submit Inter-SC Trades of Ancillary Services. Ancillary Services procured in the IFM and in the Real-Time Market are comprised of the following: Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve. ~~The HASP process evaluates the need for Energy, Regulation and Operating Reserves from System Resources and internal resources (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area) and issues binding Ancillary Services awards only for Operating Reserves Ancillary Services from Non-Dynamic System Resources.~~ Each resource for which a Scheduling Coordinator wishes to submit Ancillary Service Bids must meet the requirements set forth in this CAISO Tariff. The same resource capacity may be simultaneously offered to the same CAISO Market for multiple Ancillary Services types. Ancillary Services Bids and Submissions to Self-Provide an Ancillary Service can be submitted up to seven (7) days in advance. The CAISO will only use Operating Reserve Ramp Rates for procuring capacity associated with the specific Ancillary Services. The CAISO will issue Real-Time Dispatch Instructions in the Real-Time Market for the Energy associated with the awarded capacity based upon the applicable Operational Ramp Rate submitted with the single Energy Bid Curve in accordance with Section 30.7.7. There is no ability to procure Ancillary Services for export.
To the extent a Scheduling Coordinator has an on-demand obligation to serve loads outside the CAISO Balancing Authority Area, it can do so provided that (1) it is using export transmission capacity available in Real-Time, and (2) the resource capacity providing Energy to satisfy the on-demand obligation is not under an RMR Contract or Resource Adequacy Capacity obligation, and has not been paid a RUC Availability Payment for the Trading Hour. All resources subject to the Ancillary Services must offer requirements, as specified in Section 40.6, must submit Bids consistent with the requirements specified therein and in Section 30.

* * *

8.4.1.2 Regulation Energy Management

THIS TARIFF SECTION WILL BECOME EFFECTIVE ON NOVEMBER 27, 2012.

The CAISO will make Regulation Energy Management available to Scheduling Coordinators for Non-Generator Resources located within the CAISO Balancing Authority Area that require Energy from the Real-Time Market to offer their full capacity as Regulation. A Scheduling Coordinator for a resource using Regulation Energy Management may submit a Regulation Bid for capacity (MW) of up to four (4) times the maximum Energy (MWh) the resource can generate or curtail for fifteen (15) minutes after issuance of a Dispatch Instruction. In the Real-Time Market, a Scheduling Coordinator for a resource using Regulation Energy Management will procure Imbalance Energy as needed to satisfy the sixty (60) minute continuous Energy requirement for Regulation Awards in the Day-Ahead Market.

Scheduling Coordinators may request to use Regulation Energy Management for these Non-Generator Resources by submitting a request to certify such a resource to provide Regulation using Regulation Energy Management. The owner or operator of a Resource using Regulation Energy Management must execute both a Participating Generator Agreement and/or Participating Load Agreement and may provide only Regulation in the CAISO Market. A resource using Regulation Energy Management may not provide Energy other than Energy associated with Regulation. Scheduling Coordinators for Resources using Regulation Energy Management may define a Ramp Rate for operating as Generation and a Ramp Rate for operating as Load, respectively. These resources shall comply with the requirements to provide Regulation as specified in this Section 8, Appendix K, and the CAISO's Operating Procedures, including the requirement to undergo a market simulation using Regulation Energy Management as part of the certification procedure.

Scheduling Coordinators for resources using Regulation Energy Management shall register these resources in the Master File. Scheduling Coordinators may only submit Bids for Regulation Up and Regulation Down and Mileage for these resources. Scheduling Coordinators may not submit Energy Bids, Energy Self-Schedules, Residual Unit Commitment Bids, or Ancillary Service Bids

other than Regulation and Mileage for these resources. Scheduling Coordinators may not submit any type of commitment costs as part of their Regulation Up and Regulation Down Bids for resources using Regulation Energy Management, including Start-Up Cost, Minimum Load Costs, Pumping Cost or Pump Shut-Down Costs, or Transition Cost. All other bidding rules for Regulation set forth in Section 30 shall apply to resources using Regulation Energy Management. The CAISO will settle Dispatches from resources using Regulation Energy Management as Instructed Imbalance Energy. The portion of Demand of Non-Generator Resources using Regulation Energy Management that is dispatched as Regulation in any Settlement Interval shall not be considered Measured Demand for purposes of allocating payments and charges pursuant to Section 11 during that Settlement Interval.

The CAISO shall control the resource's operating set point through its Energy Management System with the objective of maintaining the resource's operating set point at its preferred operating point. In the Day-Ahead Market and ~~Real-Time Unit Commitment~~FMM, the procurement of Regulation from resources using Regulation Energy Management will not be constrained by the resource's MWh limit to generate, curtail the consumption of, or consume Energy continuously. In the Real-Time Dispatch, the CAISO will base the Dispatches on the resource's capability to provide Regulation. When the resource has a physical MWh limit, the CAISO will observe the resource's MWh constraint during Real-Time Dispatch and will assess whether the CAISO can support the resource's self-provided Regulation capacity or Regulation award with Real-Time Market Dispatches. To the extent the CAISO determines in the Integrated Forward Market or ~~Real Time Unit Commitment processes~~FMM that the MWh constraint of resources using Regulation Energy Management limits the capability of the CAISO, through Real-time Dispatch, to support these resources' self-provided Regulation capacity or Regulation awards, the CAISO may disqualify resources using Regulation Energy Management on a pro rata basis across the System Region from providing Regulation, which shall result in the rescission of the disqualified portion of the resources' self-provided or awarded Regulation capacity payments.

* * *

8.6.1 Ancillary Service Obligations

Each Scheduling Coordinator shall be assigned a share of the total Regulation Down, Regulation Up, Spinning Reserve, and Non-Spinning Reserve requirements by the CAISO, as set forth in Sections 11.10.2, 11.10.3 and 11.10.4, (i.e., a share of the total requirements for each Ancillary Service in the Day-Ahead Market~~, HASP,~~ and the Real-Time Market). ~~Any references in this CAISO Tariff to Regulation shall be read as referring to Regulation Up or Regulation Down.~~

8.6.2 Right To Self-Provide

Each Scheduling Coordinator may choose to self-provide all, or a portion, of its Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve obligations in the IFM, and, to the extent needed to satisfy the CAISO's additional requirement, ~~HASP and~~ the Real-Time Market, from resources eligible for self-provision, as may be permissible for any given Ancillary Service in these respective markets. The right to self-provide Ancillary Services from capacity that is under a contractual obligation to provide Energy, including but not limited to capacity subject to an RMR Contract and local Resource Adequacy Resources, shall be conditional; self-provision of Ancillary Services from such capacity will only be permitted to the extent that capacity is not needed for Energy as a result of the MPM process described in this CAISO Tariff. To self-provide Ancillary Services a Scheduling Coordinator must provide the CAISO with a Submission to Self-Provide an Ancillary Service. Both Ancillary Service Bids and Submissions to Self-Provide an Ancillary Service can be provided to the CAISO for the same Ancillary Service and for the same hour in the same market. To the extent the Submission to Self-Provide an Ancillary Service is from a resource that is a Partial Resource Adequacy Resource, and Energy is needed, including for purposes under Section 31.3.1.3, from that resource the CAISO shall only disqualify the self-provision of Ancillary Services from the portion of the resource's capacity that has must-offer obligation, provided that the Scheduling Coordinator has not submitted an Energy Bid for the capacity that is not subject to a must-offer obligation. The CAISO will treat resources subject to Resource Adequacy requirements consistently with and such resources must comply with the bidding requirements in Section 40.6. If there is an Energy Bid submitted for the capacity of a Partial Resource Adequacy Resource that is not subject to a must-offer obligation the CAISO

may disqualify the Submission to Self-Provide an Ancillary Service for the portion of the resources capacity that is not under a must-offer obligation consistent with the principles of co-optimization under the CAISO Tariff.

Prior to evaluating Ancillary Service Bids, the CAISO will determine whether Submissions to Self-Provide Ancillary Services are feasible with regard to resource operating characteristics and regional constraints and are qualified to provide the Ancillary Services in the markets for which they were submitted.

If the total Submissions to Self-Provide Ancillary Services exceed the maximum regional requirement for the relevant Ancillary Service in an Ancillary Service Region, the submissions that would otherwise be accepted by the CAISO as feasible and qualified will be awarded on a pro-rata basis among the suppliers offering to self-provide the Ancillary Service up to the amount of the Ancillary Services requirement. If a regional constraint imposes a limit on the total amount of Regulation Up, Spinning Reserve, and Non-Spinning Reserve, and the total self-provision of these Ancillary Services in that region exceeds that limit, Self-Provided AS are qualified pro rata from higher to lower quality service in three tiers: Regulation Up first, followed by Spinning Reserve, and then by Non-Spinning Reserve. Submissions to Self-Provide Ancillary Services in excess of the maximum regional requirement for the relevant Ancillary Service in an Ancillary Service Region will not be accepted and qualified by the CAISO as Self-Provided Ancillary Services.

The CAISO shall schedule Self-Provided Ancillary Services to the extent qualified in the IFM~~,~~ ~~HASP,~~ and the RTM and Dispatch Self-Provided Ancillary Services in the Real-Time. To the extent that a Scheduling Coordinator self-provides Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve, the CAISO shall correspondingly reduce the quantity of the Ancillary Services it procures from Bids submitted in the IFM~~, HASP,~~ and the Real-Time Market.

To the extent a Scheduling Coordinator's Self-Provided Ancillary Service for a particular Ancillary Service is greater than the Scheduling Coordinator's obligation for that particular Ancillary Service in a Settlement Interval, the Scheduling Coordinator will receive the user rate for the Self-

Provided Ancillary Service for the amount of the Self-Provided Ancillary Service in excess of the Scheduling Coordinator's obligation.

Scheduling Coordinators may trade Ancillary Services so that any Scheduling Coordinator may reduce its Ancillary Services Obligation through purchase of Ancillary Services capacity from another Scheduling Coordinator, or self-provide in excess of its obligation to sell Ancillary Services to another Scheduling Coordinator.

* * *

8.6.4.2 ~~HASP~~RTM

In the ~~HASP~~RTM, Scheduling Coordinators shall be required to submit information on Self-Provided Ancillary Services within the time frame stated in Section 30.1. Failure to submit the required adjusted information within the stated time frame shall lead to the self-provision being declared invalid by the CAISO.

* * *

8.7 Ancillary Services Awards

The CAISO shall provide Scheduling Coordinators with Ancillary Services Awards for the Day-Ahead~~, HASP~~ and Real-Time Markets consistent with the provisions of the CAISO Tariff. The CAISO shall post the Ancillary Service Awards and Ancillary Service Schedules for the applicable Day-Ahead Market ~~-~~no later than the publication of the Day-Ahead Schedule for the applicable Day-Ahead Market; no later than approximately forty ~~(40~~ five (45) minutes prior to the Operating Hour of ~~their Ancillary Services Awards and Ancillary Service Schedules from Non-Dynamic System Resources in the~~AS awarded as a result of a HASP Block Intertie Schedule; and no later than approximately ~~fifteen (15~~twenty-two and a half (22.5) minutes prior to the next ~~Commitment~~FMM Interval ~~in the Real-Time Market~~. Where long-term contracts are involved, the information may be treated as standing information for the duration of the contract.

~~-~~Once the CAISO has given Scheduling Coordinators notice of the Day-Ahead~~, HASP~~ and Real-Time Market Ancillary Service Awards and Ancillary Service Schedules, these awards and Schedules represent binding commitments made in the markets between the CAISO and the Scheduling Coordinators concerned, subject to any amendments issued as described above.

* * *

8.10.8.7 Rescission of Payments for Resource and Transmission Constraints

If the CAISO determines that any Day-Ahead Market award for Ancillary Services capacity or Self-Provided Ancillary Services capacity is not available during the ~~Hour-Ahead Scheduling Process or Real-Time Unit Commitment~~RTM as a result of a resource constraint, then payments for that capacity will be rescinded in accordance with Section 11.10 or, in the case of Self-Provided Ancillary Services capacity, that capacity will not be compensated at the user rate as described in Sections 11.10.2, 11.10.3 and 11.10.4.

If the CAISO determines that any Day-Ahead Market award for Ancillary Services capacity or Self-Provided Ancillary Services capacity is not available during the ~~Hour-Ahead Scheduling Process or Real-Time Unit Commitment~~RTM as a result of a Transmission Constraint, then payments for that capacity will not be rescinded, except as provided in section 11.10.9.1 for System Resources or, in the case of Self-Provided Ancillary Services capacity, that capacity will continue to be compensated at the user rate as described in Sections 11.10.2, 11.10.3 and 11.10.4.

For purposes of applying this Section to Dynamic Resources or Pseudo-Tie resources, the CAISO shall treat a reduction in the Operating Transfer Capability at an Intertie between the Day-Ahead Market and ~~Real-Time Unit Commitment~~RTM that is registered in SLIC or any successor outage management system as a Transmission Constraint. For all other constraints that cause the CAISO to determine that any Day-Ahead Market award for Ancillary Services capacity or Self-Provided Ancillary Services capacity from Dynamic Resource or Pseudo-Tie resources is not available, the ISO shall treat these constraints as resource constraints.

* * *

9.3.6.4 Changes to Maintenance Outages

A Participating TO may submit changes to its Maintenance Outage information at any time, provided, however, that if the Participating TO cancels an Approved Maintenance Outage after 5:00 a.m. of the day prior to the day upon which the Outage is scheduled to commence and the CAISO determines that the change was not required to preserve System Reliability, the CAISO

may disregard the availability of the affected facilities in determining the availability of transmission capacity in the Day-Ahead Market. The CAISO will, however, notify Market Participants and reflect the availability of transmission capacity in the ~~HASP and~~ Real-Time Market as promptly as practicable.

* * *

9.3.6.11 Cancellation of Approved Maintenance Outage

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

* * *

9.3.10.2

Each Participating TO shall report any change or potential change in equipment status of the Participating TO's transmission assets turned over to the control of the CAISO or in equipment that affects transmission assets turned over to the control of the CAISO immediately upon discovery to the CAISO (this will include line and station equipment, line protection, Remedial Action Schemes and communication problems, etc.). Each Participating TO shall also keep the CAISO immediately informed upon discovery as to any change or potential change in the Participating TO's transmission system that could affect the reliability of the CAISO Controlled Grid. This would include, but is not limited to, adverse weather conditions, fires, bomb threats, system failures, etc. To the extent possible, the CAISO shall reflect all transmission Outages in the Integrated Forward Market~~, HASP,~~ and Real-Time Market.

* * *

11.1 Settlement Principles

The CAISO shall calculate, account for and settle payments and charges with Business Associates in accordance with the following principles:

(a) The CAISO shall be responsible for calculating Settlement balances for any penalty or dispute in accordance with the CAISO Tariff, and any transmission Access Charge to UDCs or MSSs and Participating TOs;

(b) The CAISO shall create and maintain computer back-up systems, including off- site storage of all necessary computer hardware, software, records and data at an alternative location that, in the event of a Settlement system breakdown at the primary location of the day-to-day operations of the CAISO, could serve as an alternative location for day-to-day Settlement operations within a reasonable period of time;

(c) The CAISO shall retain all Settlement data records for a period which, at least, allows for the re-run of data as required by this CAISO Tariff and any adjustment rules of the Local Regulatory Authority governing the Scheduling Coordinators and their End-Use Customers and FERC;

(d) The CAISO shall calculate, account for and settle all charges and payments for Initial Settlement Statement T+3B based on CAISO estimates and for all other settlement statements based on the Settlement Quality Meter Data it has received, or, if Settlement Quality Meter Data is not available, based on the best available information or estimate it has received in accordance with the provisions in Section 10 and the applicable Business Practice Manuals; and

(e) Day-Ahead Schedules, RUC Awards and AS Awards shall be settled at the relevant LMP, RUC Price, and ASMPs, respectively. ~~HASP Intertie~~FMM Schedules shall be settled at the relevant ~~HASP Intertie~~FMM LMP at the relevant Scheduling Point. FMM AS Awards

shall be settled at the relevant FMM ASMP. All Dispatch Instructions shall be deemed delivered and settled at relevant Real-Time Market prices. Deviations from Dispatch Instructions shall be settled as Uninstructed Deviations.

* * *

11.1.2 Settlement Charges And Payments

~~The CAISO shall settle the following charges in accordance with this CAISO Tariff: (1) Grid Management Charge; (2) Bid Cost Recovery; (3) IFM charges and payments, including Energy and Ancillary Services; (4) RUC charges and payments; (5) Real-Time Market charges and payments, including Energy and Ancillary Services; (6) HASP charges and payments for Energy and Ancillary Services; (7) Regional Access Charges; (8) Wheeling Access Charges; (9) Voltage Support and Black Start charges; (10) Excess Cost Payments; (11) default interest charges; (12) CRR Charges and Payments, (13) Inter-SC Trades charges and payments; (14) neutrality adjustments; (15) FERC Annual Charges; (16) distribution of excess Marginal Losses; (17) Virtual Bid Submission Charges; (18) miscellaneous charges and payments; and (19) Participating Intermittent Resource Fees.~~

The CAISO shall settle charges and payments as specified in this Section 11.

* * *

11.2.4.4.1 Daily Clearing of the CRR Balancing Account – Full Funding of CRRs

At the end of each day, all CRR Payment shortfalls for all CRR Holders shall be paid in full and all CRR Charge shortfalls shall be fully charged through the CRR Balancing Account clearing process. The net of these CRR Charges and CRR Payment shortfalls shall be added to the CRR Balancing Account for the applicable day. Any surplus or shortfall revenue amounts in the CRR Balancing Account will be distributed to Scheduling Coordinators in an amount equal to (a) the CRR Balancing Account surplus or shortfall amounts, times (b) the ratio of each Scheduling Coordinator's Measured Demand (net of the Scheduling Coordinator's Measured Demand associated with valid and balanced ETC~~, TOR~~ or ~~Converted Rights~~TOR Self-Schedule quantities for which IFM Congestion Credits and/or ~~HASP and~~ RTM Congestion Credits were provided in

the same relevant day) divided by (c) the total Measured Demand for all Scheduling Coordinators for the relevant day (net of the total Measured Demand associated with valid and balanced ETC~~,~~ ~~TOR~~ or ~~Converted Rights~~TOR Self-Schedule quantities for which IFM Congestion Credits and/or RTM Congestion Credits were provided in the same relevant day).

* * *

11.2.4.6 ~~———~~Adjustment of CRR Revenue Related to Virtual Awards

~~Whenever the virtual bidding activity of a Convergence Bidding Entity or a reduction to a Day-Ahead import or export Schedule in the HASP has had a significant impact on the value of the CRRs in the DAM as determined in~~In accordance with this Section 11.2.4.6, the CAISO will adjust the revenue from the CRRs of a CRR Holder that is also a Convergence Bidding Entity~~. The~~ whenever either of the following creates a significant impact on the value of the CRRs held by that entity: the CRR Holder/Convergence Bidding Entity submits Virtual Bids; or the CRR Holder/Convergence Bidding Entity reduces in the RTM an import or export awarded in a Day-Ahead Schedule. As set forth in Section 11.32, the CAISO will also adjust the revenue from the CRRs of a CRR Holder (regardless of whether the CRR Holder is also a Convergence Bidding Entity) where ~~a Day-Ahead import or export Schedule of~~ the Scheduling Coordinator representing that CRR Holder ~~is reduced~~reduces in the ~~HASP as set forth~~RTM an import or export awarded in ~~Section 11.32.~~a Day-Ahead Schedule.

(a) For purposes of this Section 11.2.4.6 and the definition of Flow Impact, any reduction by a Scheduling Coordinator submitting Schedules on behalf of an entity that is a CRR Holder to an import or export Schedule in the ~~HASP~~RTM will be treated as a Virtual Award.~~-~~ For each CRR Holder subject to this Section 11.2.4.6, for each hour, and for each Transmission Constraint binding in the IFM~~, HASP,~~ or ~~RTD,~~FMM the CAISO will calculate the Flow Impact of the Virtual Awards awarded to the Scheduling Coordinator that represents the CRR Holder, excluding Virtual Awards at LAPs and generation Trading Hubs.

(b) The CAISO will determine the peak and off-peak hours of the day in which Congestion on the Transmission Constraint was significantly impacted by the Virtual Awards awarded to the Scheduling Coordinator that represents the CRR Holder. Congestion on the Transmission Constraint will be deemed to have been significantly impacted by the Virtual Awards awarded to the Scheduling Coordinator that represents the CRR Holder if the Flow Impact passes two criteria. First, the Flow Impact must be in the direction to increase the value of the CRR Holder's CRR portfolio. Second, the Flow Impact must exceed the threshold percentage of the flow limit for the Transmission Constraint. The threshold percentage is ten (10) percent of the flow limit for each Transmission Constraint.

(c) For each peak or off-peak hour that passes both criteria in Section 11.2.4.6(b), the CAISO will compare the Transmission Constraint's impact on the Day-Ahead Market value of the CRR Holder's CRR portfolio with the Transmission Constraint's impact on the ~~HASP or Real-Time Market~~FMM value of the CRR Holder's CRR portfolio, as applicable.

(d) The CAISO will adjust the peak or off-peak period revenue from the CRR Holder's CRRs in the event that, over the peak or off-peak period of a day, the Transmission Constraint's contribution to the Day-Ahead Market value of the CRR Holder's CRR portfolio exceeds the Transmission Constraint's contribution to the ~~HASP or Real-Time Market~~FMM value of the CRR Holder's CRR portfolio, as applicable. The amount of the peak period adjustment will be the amount by which the Transmission Constraint's contribution to the Day-Ahead Market value of the CRR Holder's CRR portfolio exceeds the Transmission Constraint's contribution to the ~~HASP or Real-Time Market~~FMM value of the CRR

Holder's CRR portfolio for the peak-period hours that passed both criteria in Section 11.2.4.6(b), as applicable. The amount of the off-peak period adjustment will be the amount by which the Transmission Constraint's contribution to the Day-Ahead Market value of the CRR Holder's CRR portfolio exceeds the Transmission Constraint's contribution to the HASP or Real-Time MarketFMM value of the CRR Holder's CRR portfolio for the off-peak period hours that passed both criteria in Section 11.2.4.6(b), as applicable.

All adjustments of CRR revenue calculated pursuant to this Section 11.2.4.6 will be added to the CRR Balancing Account.

* * *

11.3 Settlement of Virtual Awards

11.3.1 Virtual Supply Awards

The CAISO will pay each Scheduling Coordinator with Virtual Supply Awards at an Eligible PNode or Eligible Aggregated PNode an amount equal to the Day-Ahead LMP at the Eligible PNode or Eligible Aggregated PNode multiplied by the MWhs of Virtual Supply Awards. Virtual Supply Awards subject to price correction will be settled as specified in Section 11.21. The CAISO will charge each Scheduling Coordinator with Virtual Supply Awards at an Eligible PNode or Eligible Aggregated PNode an amount equal to the simple hourly average of the Dispatch Interval Real-Timefour FMM LMPs for the applicable Trading Hour at the Eligible PNode or Eligible Aggregated PNode multiplied by the MWhs of Virtual Supply Awards.

11.3.2 Virtual Demand Awards

The CAISO will charge each Scheduling Coordinator with Virtual Demand Awards at an Eligible PNode or Eligible Aggregated PNode an amount equal to the Day-Ahead Market LMP at the Eligible PNode or Eligible Aggregated PNode multiplied by the MWhs of Virtual Demand Awards. Virtual Demand Awards subject to price correction will be settled as specified in Section 11.21. The CAISO will pay each Scheduling Coordinator with Virtual Demand Awards at an Eligible PNode or Eligible Aggregated PNode an amount equal to the simple hourly average of the

~~Dispatch Interval Real-Time~~four FMM LMPs for the applicable Trading Hour at the Eligible PNode or Eligible Aggregated PNode multiplied by the IFM MWhs of Virtual Demand Awards.

11.4 ~~HASP Settlement Of Scheduling Points~~ [Not Used]

~~The CAISO shall settle both incremental and decremental Energy at the relevant Scheduling Points including Operational Adjustments for all Non-Dynamic System Resources based on the HASP Intertie LMP in accordance with Sections 11.4.1, 11.4.2 and 11.32. Energy dispatched using HASP Intertie Schedules is accounted as Instructed Imbalance Energy and its costs shall be included in the Real-Time Market Settlements in accordance with Section 11.5.~~

11.4.1 [Not Used]~~HASP Settlement For Exports~~

~~For each Settlement Period that the CAISO clears Energy transactions at Scheduling Points in HASP, the Settlement for such transactions will be the CAISO HASP Intertie LMP multiplied by the MWh quantity of export scheduled at the individual Scheduling Point in excess of or less than the Day-Ahead Schedule, respectively. For Scheduling Coordinators whose exports scheduled at the individual Scheduling Point is subject to an upward price correction as specified in Section 11.21, the CAISO will use the Price Correction Derived LMP to settle the MWh quantity of Energy exports scheduled in excess of the Day-Ahead Schedule at the relevant Scheduling Point.~~

11.4.2 [Not Used]~~HASP Settlement For Imports~~

~~For each Settlement Period that the CAISO clears Energy transactions at Scheduling Points for all Non-Dynamic System Resources in HASP, the CAISO shall pay or charge Scheduling Coordinators for each System Resource an amount equal to the HASP Intertie LMP multiplied by the MWh quantity of import scheduled at the individual Scheduling Point in excess of or less than the import at that Scheduling Point scheduled in the Day-Ahead Schedule, respectively.~~

11.5 Real-Time Market Settlements

The CAISO shall calculate and account for Imbalance Energy for each Dispatch Interval and settle Imbalance Energy in the Real-Time Market for each Settlement Interval for each resource within the CAISO Balancing Authority Area and all System Resources dispatched in Real-Time. There are two categories of Imbalance Energy: FMM Instructed Imbalance Energy and RTD Imbalance Energy. RTD Imbalance Energy consists of RTD IIE and UIE. FMM IIE includes all

Energy associated with the FMM Schedule. FMM Instructed Imbalance Energy is settled pursuant to Section 11.5.1.1, including any Energy related with HASP Intertie Block Schedules~~.~~ cleared through the FMM. RTD IIE is settled pursuant to Section 11.5.1.2 and UIE is settled pursuant to Section 11.5.2. In addition, the CAISO shall settle UFE as part of the Real-Time Market Settlements. To the extent that the sum of the Settlements Amounts for FMM IIE, RTD IIE, and UIE does not equal zero, the CAISO will assess charges or make payments for the resulting differences to all Scheduling Coordinators based on a pro rata share of their Measured Demand for the relevant Settlement Interval, as further described in Section 11.5.4. ~~–~~Imbalance Energy due to Exceptional Dispatches, as well as the allocation of related costs, including Excess Costs Payments is settled as described in Section 11.5.6. The CAISO shall reverse RTM Congestion Charges for valid and balanced ETC and TOR Self-Schedules as described in Section 11.5.7. The CAISO will settle Energy for emergency assistance as described in Section 11.5.8.

11.5.1 Imbalance Energy Settlements

11.5.1.1 FMM Instructed Imbalance Energy Settlements

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

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

11.5.1.2 RTD Instructed Imbalance Energy Settlements

For each Settlement Interval, RTD IIE consists of the following types of Energy: (1) RTD Optimal Energy; (2) Residual Imbalance Energy; (3) RTD Minimum Load Energy; (4) RTD Exceptional Dispatch Energy; (5) Regulation Energy; (6) Standard Ramping Energy; (7) Ramping Energy Deviation; (8) RTD Derate Energy; (9) MSS Load Following Energy; (10) RTD Pumping Energy; and (11) Operational Adjustments. Payments and charges for RTD IIE attributable to each resource in each Settlement Interval shall be settled by debiting or crediting, as appropriate, the specific Scheduling Coordinator's RTD IIE Settlement Amount. The RTD IIE Settlement Amounts for the Standard Ramping Energy shall be zero. The RTD IIE Settlement Amounts for RTD Optimal Energy, RTD Minimum Load Energy, Regulation Energy, Ramping Energy Deviation, RTD Derate Energy, and RTD Pumping Energy shall be calculated as the product of the sum of all of these types of Energy and the RTD LMP. For MSS Operators that have elected net Settlement, the RTD IIE Settlement Amounts for Energy dispatched through the RTD optimization shall be calculated as the product of the RTD MSS Price and the sum of the following types of Energy: RTD Minimum Load Energy from System Units dispatched in Real-Time, Regulation

Energy, Ramping Energy Deviation, RTD Derate Energy, MSS Load Following Energy, and RTD Pumping Energy. For MSS Operators that have elected gross Settlement, regardless of whether that entity has elected to follow its Load or to participate in RUC, the RTD IIE for such entities is settled similarly to non-MSS entities as provided in this Section 11.5.1. The remaining RTD IIE Settlement Amounts are determined as follows: (1) IIE Settlement Amounts for Residual Imbalance Energy are determined pursuant to Section 11.5.5.; and (~~3~~)2) RTD IIE Settlement Amounts for Exceptional Dispatches are settled pursuant to Section 11.5.6.

11.5.2 Uninstructed Imbalance Energy

~~**11.5.1.1 Total IIE Settlement Amount**~~

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

~~**11.5.1.2 Total IIE Quantity**~~

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

~~**11.5.2 Uninstructed Imbalance Energy**~~

Scheduling Coordinators shall be paid or charged a UIE Settlement Amount for each LAP, PNode or Scheduling Point for which the CAISO calculates a UIE quantity~~.~~ for each Settlement Interval. UIE quantities are calculated for each resource that has a Day-Ahead Schedule, Dispatch Instruction, Real-Time Interchange Export Schedule or Metered Quantity. For MSS Operators electing gross Settlement, regardless of whether that entity has elected to follow its Load or to

participate in RUC, the UIE for such entities is settled similarly to how UIE for non-MSS entities is settled as provided in this Section 11.5.2. The CAISO shall account for UIE ~~in two categories: (1) Tier 1 UIE is accounted as the quantity deviation from~~every five minutes based on the resource's ~~IIE; and (2) Tier 2 UIE is accounted as the quantity deviation from the resource's Day-Ahead Schedule or as described in Section 11.2.5.4.~~ Dispatch Instruction. For all resources, including Generating Units, System Units of MSS Operators that have elected gross Settlement, Physical Scheduling Plants, System Resources and all Participating Load and Proxy Demand Resources, the ~~Tier 1~~ UIE Settlement Amount is calculated for each Settlement Interval as the product of its ~~Tier 1~~ UIE MWh quantity and ~~its Resource-Specific Tier 1 UIE Settlement Interval Price as calculated per Section 11.5.2.1, and~~ the ~~Tier 2 UIE Settlement Amount is calculated for each Settlement Interval as the product of its Tier 2 UIE quantity and the simple average of the relevant Dispatch Interval LMPs.~~applicable RTD LMP. . The ~~Tier 2~~ UIE Settlement Amount for non-Participating Load and MSS Demand under gross Settlement is settled as described in Section 11.5.2.2. For MSS Operators that have elected net Settlement, the ~~Tier 1~~ UIE Settlement Amount is calculated for each Settlement Interval as the product of its ~~Tier 1~~ UIE quantity and its ~~Real-Time Settlement Interval MSS Price and the Tier 2 UIE Settlement Amount is calculated for each Settlement Interval as the product of its Tier 2 UIE quantity and the~~ Real-Time Settlement Interval MSS Price.

* * *

11.5.2.2 Hourly Real-Time ~~LAP Price~~Demand Settlement

~~The Hourly Real-Time Default LAP Price will apply to Demand and MSS Demand under net Settlement of Imbalance Energy, except for Demand not settled at the Default LAP as provided in Section 30.5.3.2. The Default or Custom LAP Hourly Real-Time LAP Price is calculated as the simple average of the Dispatch Interval LMPs for the Default or Custom LAP for the applicable Trading Hour. The Dispatch Interval LMP for CAISO Demand settled a given Default LAP is determined as specified in in Section 27.2.2.2.1. The Dispatch Interval LMP for CAISO Demand settled at a Custom LAP is determined as specified in Section 27.2.2.2.2.~~The Default LAP Hourly Real-Time Price will apply to CAISO Demand and MSS Demand under net Settlement of

Imbalance Energy, except for CAISO Demand not settled at the Default LAP as provided in Section 30.5.3.2. For each Settlement Interval, the differences between the Day-Ahead Scheduled CAISO Demand and Metered Demand (MWh) is settled at the Default LAP Hourly Real-Time Price or the Custom LAP Hourly Real-Time Price, as appropriate. For each Default LAP, the CAISO calculates the applicable Default LAP Hourly Real-Time Price as the weighted average LMP of the four Default LAP FMM LMPs and the twelve (12) five-minute Default LAP RTD LMPs. The CAISO calculates the weighted average LMP for each Default LAP as the summation of the weighted average SMEC, the weighted average MCC, and the weighted average MCL for that Default LAP. The CAISO calculates the weighted average SMEC, MCC, and MCL for each applicable Trading Hour based on the four applicable Default LAP FMM SMECs, MCCs, and MCLs, respectively, and the twelve (12) applicable Default LAP RTD SMECs, MCCs, and MCLs, respectively. For each Custom LAP, the CAISO calculates the applicable Custom LAP Hourly Real-Time Price as the weighted average LMP of the four Custom LAP FMM LMPs and the twelve (12) five-minute Custom LAP RTD LMPs. The CAISO calculates the weighted average LMP for each Custom LAP as the summation of the weighted average SMEC, the weighted average MCC, and the weighted average MCL for that Custom LAP. The CAISO calculates the weighted average SMEC, MCC, and MCL for each applicable Trading Hour based on the four applicable Custom LAP FMM SMECs, MCCs, and MCLs, respectively, and the twelve (12) applicable Custom LAP RTD SMECs, MCCs, and MCLs, respectively. In calculating the weighted average SMEC, MCC, and MCL for each hour for either the Default LAPs or Custom LAPs, the CAISO determines the weights based on the difference between Day-Ahead Schedules at the applicable LAP and the CAISO Forecast of CAISO Demand used in the FMM multiplied by the relevant FMM LMP at the applicable LAP plus the difference between the CAISO Forecast of CAISO Demand used in the FMM and the CAISO Forecast of CAISO Demand used in the RTD multiplied by the relevant RTD LMP at the applicable LAP divided by the sum of the difference between Day-Ahead Schedules at the applicable LAP and the CAISO Forecast of CAISO Demand used in the FMM plus the difference between the CAISO Forecast Of CAISO Demand used in the FMM and the CAISO Forecast Of CAISO Demand used in the

RTD. Furthermore, the Default LAP Hourly Real-Time Prices and the Custom LAP Hourly Real-Time Prices will be bounded by the maximum positive LMP and the lowest negative LMP for the applicable Trading Hour from those relevant intervals at the relevant LAP. If the calculated price exceeds the upper boundary or is below the lower boundary, then the Default LAP Hourly Real-Time Price or the Custom LAP Hourly Real-Time Price, as appropriate, instead will be calculated based on a weighted average price with the weightings based on gross deviations (absolute value of each deviation).

The Default LAP Hourly Real-Time Prices and the Custom LAP Hourly Real-Time Prices are further determined by the requirements in Section 27.2.2.2.1 and 27.2.2.2.2, respectively.

11.5.2.3 Revenue Neutrality Resulting from Changes in LAP Load Distribution Factors

Any resulting revenue from changes in the LAP Load Distribution Factors between the Day-Ahead Market and the Real-Time ~~Market~~Dispatch shall be allocated to metered CAISO Demand in the corresponding Default LAP.

* * *

11.5.3 Unaccounted For Energy (UFE)

For each Settlement Interval, the CAISO will calculate UFE for each utility Service Area for which the IOU or Local Publicly Owned Electric Utility has requested separate UFE calculation and has met the requirements applicable to a CAISO Metered Entity. The UFE will be settled as Imbalance Energy at the ~~Settlement Interval Locational Marginal~~Default LAP Hourly Real-Time Price calculated for each utility Service Area for which UFE is calculated separately. UFE will be allocated to each Scheduling Coordinator based on the ratio of its metered CAISO Demand within the relevant utility Service Area for which UFE is calculated separately to total metered CAISO Demand within that utility Service Area. UFE charges will not be estimated or included on Initial Settlement Statement T+3B.

11.5.4 Imbalance Energy Pricing; Non-Zero Offset Amount Allocation

11.5.4.1 ~~Application and Calculation of Dispatch Interval LMPs~~[Not Used]

~~Payments to Scheduling Coordinators, including Scheduling Coordinators for MSS Operators that have elected gross Settlement, that supply Imbalance Energy will be based on Resource-Specific Settlement Interval LMPs. The Resource-Specific Settlement Interval LMPs are established using Dispatch Interval LMPs. Dispatch Interval LMPs will apply to Generating Units, System Units for MSS Operators that have elected gross Settlement, Physical Scheduling Plants, Dynamic System Resources, the Demand response portion of a Participating Load, and Proxy Demand Resources for Settlement of Imbalance Energy. The Dispatch Interval LMP will be calculated at each PNode associated with such resource irrespective of whether the resource at that PNode has received Dispatch Instructions. The Dispatch Interval LMPs are then used to calculate a Resource-Specific Settlement Interval LMP and a Resource Specific Tier 1 UIE Settlement Interval Price for each Generating Unit, System Unit or MSS Operator that has elected gross Settlement, Physical Scheduling Plant, Dynamic System Resource, Participating Load, and Proxy Demand Resource within the CAISO Controlled Grid. Payments to Scheduling Coordinators for MSS Operators that have elected net Settlement that supply Imbalance Energy will be based on the Real-Time Settlement Interval MSS Price.~~

11.5.4.2 Allocations of Non-Zero Amounts of the Sum of IIE, UIE, UFE, the Real-Time Ancillary Services Congestion Revenues and Real-Time Virtual Awards Settlements

The CAISO will first compute (1) the Real-Time Congestion Offset and allocate it to all Scheduling Coordinators, based on Measured Demand, excluding Demand associated with ETC or TOR Self-Schedules for which a ~~HASP and~~ RTM Congestion Credit was provided as specified in Section 11.5.7, and excluding Demand associated with ETC, Converted Right, or TOR Self-Schedules for which an IFM Congestion Credit was provided as specified in Section 11.2.1.5; and (2) the Real-Time Marginal Cost of Losses Offset and allocate it to all Scheduling Coordinators based on Measured Demand, excluding Demand associated with TOR Self-Schedules for which a RTM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules was provided as specified in Section 11.5.7.2~~-~~, and excluding Demand associated with TOR Self-Schedules for which an IFM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules was provided as specified in

Section 11.2.1.7. For Scheduling Coordinators for MSS operators that have elected to Load follow or net settlement, or both, the Real-Time Marginal Cost of Losses Offset will be allocated based on their MSS Aggregation Net Measured Demand excluding Demand associated with TOR Self-Schedules for which a RTM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules was provided as specified in Section 11.5.7.2, and excluding Demand associated with TOR Self-Schedules for which an IFM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules was provided as specified in Section 11.2.1.7. For Scheduling Coordinators for MSS Operators regardless of whether the MSS Operator has elected gross or net Settlement, the CAISO will allocate the Real-Time Congestion Offset based on the MSS Aggregation Net Non-ETC/TOR Measured Demand. To the extent that the sum of the Settlement amounts for IIE, UIE, UFE, the Real-Time Ancillary Services Congestion revenues and Virtual Awards settlements in the ~~HASP and~~ Real-Time Market in accordance with Section 11.3, less Real-Time Congestion Offset, and less the Real-Time Marginal Cost of Losses Offset, does not equal zero, the CAISO will assess charges or make payments for the resulting differences to all Scheduling Coordinators, including Scheduling Coordinators for MSS Operators that are not Load following MSSs and have elected gross Settlement, based on a pro rata share of their Measured Demand for the relevant Settlement Interval. For Scheduling Coordinators for MSS Operators that have elected net Settlement, the CAISO will assess charges or make payments for the resulting non-zero differences of the sum of the Settlement amounts for IIE, UIE, and UFE, the Real-Time Ancillary Services Congestion Revenues and Virtual Awards settlements in the ~~HASP and~~ Real-Time Market in accordance with Section 11.3, less Real-Time Congestion Offset and less the Real-Time Marginal Cost of Losses Offset, based on their MSS Aggregation Net Measured Demand. For Scheduling Coordinators for MSS Operators that have elected Load following, the CAISO will not assess any charges or make payments for the resulting non-zero differences of the sum of the Settlement amounts for IIE, UIE, and UFE, the Real-Time Ancillary Services Congestion Revenues and Virtual Awards settlements in the ~~HASP and~~ Real-Time Market in accordance with Section 11.3, less Real-Time Congestion Offset and less the Real-Time Marginal Cost of Losses Offset.

11.5.5 – Settlement Amount for Residual Imbalance Energy

For each Settlement Interval, Residual Imbalance Energy settlement amounts shall be the product of the MWh of Residual Imbalance Energy for that Settlement Interval and the Bid, as mitigated pursuant to Section 39.7 that led to the Residual Imbalance Energy from the relevant Dispatch Interval in which the resource was dispatched, subject to additional rules specified in this section below and in Section 11.17. The relevant Dispatch Interval and Bid that led to the Residual Imbalance Energy may occur prior or subsequent to the interval in which the relevant Residual Imbalance Energy occurs and can be contiguous, or not, with the applicable Trading Hour in which the relevant Residual Imbalance Energy Settlement Interval occurs. For MSS Operators the Settlement for Residual Imbalance Energy is conducted in the same manner, regardless of any MSS elections (net/gross Settlement, Load following or opt-in/opt-out of RUC). When a Scheduling Coordinator increases the Minimum Load amount for a resource through SLIC, for the Settlement Interval(s) during which the affected resource is ramping up towards or ramping down from such a Minimum Load change, the Residual Imbalance Energy for the applicable Settlement Interval(s) will be re-classified as Derate Energy and will be paid at the applicable RTD Locational Marginal Price.

11.5.6 Settlement Amounts For IIE From Exceptional Dispatch

For each Settlement Interval, the IIE Settlement Amount from each type of Exceptional Dispatch described in Section 34.~~9~~11 is calculated as the sum of the products of the relevant FMM IIE or RTD IIE quantity for the ~~Dispatch~~Settlement Interval and the relevant FMM or RTD Settlement price ~~for the Dispatch Interval~~ for each type of Exceptional Dispatch as further described in this Section 11.5.6. For MSS Operators the Settlement for FMM or RTD IIE from Exceptional Dispatches is conducted in the same manner, regardless of any MSS elections (net/gross Settlement, Load following or opt-in/opt-out of RUC). Except for the Settlement price, Exceptional Dispatches to perform Ancillary Services testing, to perform PMax testing, and to perform pre-commercial operation testing for Generating Units are otherwise settled in the same manner as provided in Section 11.5.6.1. Notwithstanding any other provisions of this Section 11.5.6, the Exceptional Dispatch Settlement price that is applicable in circumstances in which the CAISO

applies Mitigation Measures to Exceptional Dispatch of resources pursuant to Section 39.10 shall be calculated as set forth in Section 11.5.6.7.

11.5.6.1 Settlement for FMM or RTD IIE from Exceptional Dispatches used for System Emergency Conditions, for a Market Interruption, to Mitigate Overgeneration Conditions or to Prevent or Relieve Imminent System Emergencies

The Exceptional Dispatch Settlement price for incremental FMM or RTD IIE that is delivered as a result of an Exceptional Dispatch for System Emergency conditions, for a Market Interruption, to mitigate Overgeneration conditions, or to prevent or relieve an imminent System Emergency, including forced Start-Ups and Shut-Downs, is the higher of the (a) ~~Resource-Specific Settlement Interval~~applicable FMM or RTD LMP, (b) the Energy Bid price, (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. Costs for incremental Energy for this type of Exceptional Dispatch are settled in two payments: (1) incremental Energy is first settled at the ~~Resource-Specific Settlement Interval~~ applicable FMM or RTD LMP and included in the total IIE Settlement Amount described in Section 11.5.1.1; and (2) the incremental Energy Bid Cost in excess of the applicable FMM or RTD LMP at the relevant Location is settled pursuant to Section 11.5.6.1.1. The Exceptional Dispatch Settlement price for decremental IIE that is delivered as a result of an Exceptional Dispatch Instruction for a Market Interruption, or to prevent or relieve a System Emergency, is the minimum of (a) the ~~Resource-Specific Settlement Interval~~FMM or RTD LMP, (b) the Energy Bid price subject to Section 39.6.1.4, (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. All Energy costs for decremental IIE associated with this type of Exceptional Dispatch are included in the total IIE Settlement Amount described in Section 11.5.1.1.

11.5.6.1.1 Settlement of Excess Cost Payments for Exceptional Dispatches used for System Emergency Conditions, for a Market Interruption, and to Avoid an Imminent System Emergency

The Excess Cost Payment for incremental Exceptional Dispatches used for emergency conditions, for a Market Interruption, or to avoid an imminent System Emergency is calculated for each resource for each Settlement Interval as the cost difference between the Settlement amount calculated pursuant to Section 11.5.6.1 for the applicable Exceptional Dispatch at the ~~Resource-Specific Settlement Interval~~FMM or RTD LMP and delivered Exceptional Dispatch quantity at one of the following three costs: (1) the resource's Energy Bid Cost, (2) the Default Energy Bid cost, or (3) the Energy cost at the negotiated price, as applicable for System Resources, for the relevant Exceptional Dispatch.

11.5.6.2 Settlement of IIE from Exceptional Dispatches Caused by Modeling Limitations

The Exceptional Dispatch Settlement price for IIE that is consumed or delivered as a result of an Exceptional Dispatch to mitigate or resolve Congestion as a result of a transmission-related modeling limitation in the FNM as described in Section 34.~~9~~11.3 is the maximum of (a) the ~~Resource-Specific Settlement Interval~~FMM or RTD LMP, (b) the Energy Bid price, (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. Costs for incremental Energy for this type of Exceptional Dispatch are settled in two payments: (1) incremental Energy is first settled at the ~~Resource-Specific Settlement Interval~~FMM or RTD LMP and included in the total IIE Settlement Amount described in Section 11.5.1.1; and (2) the incremental Energy Bid costs in excess of the applicable LMP at the relevant Location are settled per Section 11.5.6.2.3. The Exceptional Dispatch Settlement price for decremental IIE for this type of Exceptional Dispatch is the minimum of (a) the ~~Resource-Specific Settlement Interval~~FMM or RTD LMP, (b) the Energy Bid price, (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. Costs for decremental IIE associated with this type of Exceptional Dispatch are settled in two payments: (1) decremental Energy is first settled at the ~~Resource-Specific Settlement Interval~~FMM or RTD LMP and included in the total IIE

Settlement Amount described in Section 11.5.1.1; and (2) the decremental Energy Bid costs in excess of the applicable LMP at the relevant Location are settled per Section 11.5.6.2.3.

* * *

11.5.6.2.2 [NOT USED]

11.5.6.2.3 Settlement of Excess Cost Payments for Exceptional Dispatches used for Transmission-Related Modeling Limitations

The Excess Cost Payment for Exceptional Dispatches used for transmission-related modeling limitations as described in Section 34.~~9~~11.3 is calculated for each resource for each Settlement Interval as the cost difference between the Settlement amount calculated pursuant to Section 11.5.6.2.1 or 11.5.6.2.2 for the applicable delivered Exceptional Dispatch quantity at the ~~Resource-Specific Settlement Interval~~FMM or RTD LMP and one of the following three costs: (1) the resource's Energy Bid Cost, 2) the Default Energy Bid cost, or 3) the Energy cost at the negotiated price, as applicable for System Resources, for the relevant Exceptional Dispatch.

11.5.6.2.4 Exceptional Dispatches for Non-Transmission-Related Modeling Limitations

The Exceptional Dispatch Settlement price for incremental IIE that is consumed or delivered as a result of an Exceptional Dispatch to mitigate or resolve Congestion that is not a result of a transmission-related modeling limitation in the FNM as described in Section 34.~~9~~11.3 is the maximum of the (a) ~~Resource-Specific Settlement Interval~~FMM or RTD LMP, (b) Energy Bid price, (c) the Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) the negotiated price as applicable to System Resources. All costs for incremental Energy for this type of Exceptional Dispatch will be included in the total IIE Settlement Amount described in Section 11.5.1.1. The Exceptional Dispatch Settlement price for decremental IIE for this type of Exceptional Dispatch is the minimum of the (a) ~~Resource-Specific Settlement Interval~~FMM or RTD LMP, (b) Energy Bid Price, (c) ~~or the~~ Default Energy Bid price if the resource has been mitigated through the MPM in the Real-Time Market and for the Energy that does not have an Energy Bid price, or (d) ~~the~~ negotiated price as applicable to System Resources. All costs for

decremental IIE associated with this type of Exceptional Dispatch are included in the total IIE Settlement Amount described in Section 11.5.1.1.

* * *

11.5.6.4 Settlement of IIE from Exceptional Dispatches for Testing

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

* * *

11.5.6.6 Settlement of IIE from Exceptional Dispatches for ~~HASP and~~ Real-Time ETC and TOR Self-Schedules

The Exceptional Dispatch Settlement price for IIE from ~~HASP and~~ Real-Time ETC and TOR Self-Schedules shall be the ~~Resource-Specific Settlement Interval~~FMM or RTD LMP. The IIE Settlement Amount for this type of Exceptional Dispatch shall be calculated as the product of the sum of all of these types of Energy and the ~~Resource-Specific Settlement Interval LMP.~~FMM or RTD LMP. All Energy costs for these types of Exceptional Dispatches will be included in the IIE Settlement Amount described in Section 11.5.1.1.

11.5.6.7 ~~[NOT USED]~~ Settlement of Exceptional Dispatch Energy

11.5.6.7.1 Settlement of Exceptional Dispatch Energy from Exceptional Dispatches of Resources Eligible for Supplemental Revenues

Except as specified in Section 11.5.6.7.3, the Exceptional Dispatch Settlement price for the Exceptional Dispatch Energy delivered by a resource that satisfies all of the criteria set forth in Section 39.10.1 shall be the higher of (a) the resource's Energy Bid price or (b) the ~~Resource-Specific Settlement Interval~~FMM or RTD LMP.

* * *

11.5.6.7.3 Exception to the Other Provisions of Section 11.5.6.7

Notwithstanding any other provisions of this Section 11.5.6.7, if the Energy Bid price for a resource that satisfies all of the criteria set forth in Sections 39.10.1 or 39.10.2 is lower than the Default Energy Bid price for the resource, and the ~~Resource-Specific Settlement Interval~~FMM or RTD LMP is lower than both the Energy Bid price for the resource and the Default Energy Bid price for the resource, the Exceptional Dispatch Settlement price for the Exceptional Dispatch Energy delivered by the resource shall be the Energy Bid price for the resource.

11.5.7 Congestion Credit And Marginal Cost Of Losses Credit

11.5.7.1 ~~HASP and~~ RTM Congestion Credit for ETCs and TORs

The CAISO shall not apply charges or payments to Scheduling Coordinators related to the MCC associated with all Points of Receipt and Points of Delivery pairs associated with valid and balanced ETC Self-Schedules or TOR Self-Schedules~~.~~ after the Day-Ahead Market. The balanced portion ~~will~~for each ETC or TOR contract for each Settlement Interval will be based on the difference between: (1) the minimum of (a) the ~~metered CAISO~~total Demand, (b) the total ETC or TOR Supply Self-Schedule submitted in ~~the HASP, or~~RTM, including changes after twenty (20) minutes before the applicable Trading Hour if such change is permitted by the Existing Contract, or (c) the Existing Contract maximum capacity as specified in the TRTC Instructions; and (2) the valid and balanced portion of the Day-Ahead Schedule. In determining the balanced portions, the CAISO evaluates the amounts based on the following variables: (a) for exports and imports, the CAISO shall use the schedule quantity specified in the Interchange schedule used for check out between CAISO and other Balancing Authority Areas; (b) for CAISO Demand, the CAISO shall use the metered CAISO Demand associated with the applicable ETC or TOR; and (c) for all Generation the CAISO shall use the quantity specified in the Dispatch Instructions. For each Scheduling Coordinator, the CAISO shall determine for each Settlement Interval the applicable ~~HASP and~~ RTM Congestion Credit for Imbalance Energy, which can be positive or negative, as the sum of the product of the relevant MWh quantity and the weighted average MCC at each Point of Receipt and Point of Delivery associated with the valid and balanced portions of that Scheduling Coordinator's ETC or TOR Self-Schedules. ~~For all exports and imports settled in the HASP, the CAISO shall use the MWh quantity specified in the CAISO's~~

~~Interchange transactional scheduling system schedule. For all Demand settled in the Real-Time Market the CAISO shall use the metered CAISO Demand associated with the applicable ETC or TOR. For all Supply settled in the Real-Time Market the CAISO shall use the quantity specified in the Dispatch Instructions.~~ The weights in the two markets will be based on the absolute values of the (a) deviation of the FMM Schedule or the CAISO Forecast Of CAISO Demand used in the FMM from Day-Ahead Schedules and (b) deviation of the RTD schedule or the CAISO Forecast Of CAISO Demand used in the RTD from Day-Ahead Schedules.

11.5.7.2 RTM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules

For all Points of Receipt and Points of Delivery pairs associated with a valid and balanced TOR Self-Schedule submitted to the ~~HASP or~~ RTM pursuant to an existing agreement between the TOR holder and either the CAISO or a Participating TO as specified in Section 17.3.3, the CAISO shall not impose any charge or make any payment to the Scheduling Coordinator related to the MCL associated with such TOR Self-Schedules and will instead impose any applicable charges for losses as specified in the existing agreement between the TOR holder and either the CAISO or a Participating TO applicable to the relevant TOR. In any case in which the TOR holder has an existing agreement regarding its TORs with either the CAISO or a Participating TO, the provisions of the agreement shall prevail over any conflicting provisions of this Section 11.5.7.2. Where the provisions of this Section 11.5.7.2 do not conflict with the provisions of the agreement, the provisions of this Section 11.5.7.2 shall apply to the subject TORs. The balanced portion of the TOR Self-Schedule ~~will based on the difference between: (1) minimum of~~after the Day-Ahead Market is the ~~metered CAISO Demand or~~ same balanced quantity mentioned in this Section 11.5.7.2 for the TOR Self-Schedule ~~submitted in the HASP, or the TOR maximum capacity as specified in the TRTC Instructions; and (2) the Day-Ahead Schedule.~~ . For each Scheduling Coordinator, the CAISO shall determine for each Settlement Interval the applicable RTM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules for Imbalance Energy, which can be positive or negative, as the sum of the product of the relevant MWh quantity and the weighted average MCL at each eligible Points of Receipt and Points of Delivery associated with the valid and balanced portions of that Scheduling Coordinator's TOR Self-Schedules. ~~For all exports and~~

~~imports settled in the HASP, the CAISO shall use the MWh quantity specified in the HASP Intertie Schedule. For all Demand settled in the Real-Time Market the CAISO shall use the metered CAISO Demand associated with the applicable TOR. For all Supply settled in the Real-Time Market the CAISO shall use the quantity specified in the Dispatch Instructions~~ The weights in the two markets will be based on the absolute values of the: (a) deviation of the FMM Schedule or the CAISO Forecast Of CAISO Demand used in the FMM from Day-Ahead Schedules; and (b) deviation of the RTD schedule or the CAISO Forecast Of CAISO Demand used in the RTD from Day-Ahead Schedules. For losses that the CAISO shall charge pursuant to Section 17.3.3, the specific loss charge amount shall be the product of (a) the specific loss percentage as may be specified in an applicable agreement between the TOR holder and the CAISO or an existing agreement between the TOR holder and a Participating TO, (b) the weighted average SMEC price from the FMM and RTD markets with weights based on the absolute values of (1) deviation of FMM schedule or CAISO Forecast Of CAISO Demand used in the FMM from Day-Ahead Schedules and (2) deviation of RTD schedule or CAISO Forecast Of CAISO Demand used in the RTD from Day-Ahead Schedules, and (c) the balanced contract quantity mentioned in Section 11.5.7.1.

* * *

11.5.8.1 Settlement for Energy Purchased by the CAISO for System Emergency Conditions, to Avoid Market Interruption, or to Prevent or Relieve Imminent System Emergencies, Other than Exceptional Dispatch Energy

The Settlement price for Energy that is delivered to the CAISO from a utility in another Balancing Authority Area as a result of a CAISO request pursuant to Section 42.1.5 or any other provision for assistance in System Emergency conditions, to avoid a Market Interruption, or to prevent or relieve an imminent System Emergency, other than Energy from an Exceptional Dispatch, shall be either (i) a negotiated price agreed upon by the CAISO and the seller or (ii) a price established by the seller for such emergency assistance in advance, as may be applicable. In the event no Settlement price is established prior to the delivery of the emergency Energy, the default

Settlement price shall be the simple average of the relevant ~~Dispatch Interval~~FMM and RTD LMPs at the applicable Scheduling Point, plus all other charges applicable to imports to the CAISO Balancing Authority Area, as specified in the CAISO Tariff. If the default Settlement price is determined by the seller not to compensate the seller for the value of the emergency Energy delivered to the CAISO, then the seller shall have the opportunity to provide the CAISO with cost support information demonstrating that a higher price is justified. The cost support information must be provided in writing to the CAISO within thirty (30) days following the date of the provision of emergency assistance. The CAISO shall have the discretion to pay that higher price based on the seller's justification of this higher price. The CAISO will provide notice of its determination whether to pay such a higher price within thirty (30) days after receipt of the cost support information. Any dispute regarding the CAISO's determination whether to pay a higher price for emergency assistance based on cost support information shall be subject to the CAISO ADR Procedures. Payment by the CAISO for such emergency assistance will be made in accordance with the Settlement process, billing cycle, and payment timeline set forth in the CAISO Tariff. The costs for such emergency assistance, including the payment of a price based on cost support information, will be settled in two payments: (1) the costs will first be settled at the simple average of the relevant Dispatch Interval LMPs and included in the total IIE Settlement Amount as described in Section 11.5.~~1~~2.1; and (2) costs in excess of the simple average of the relevant Dispatch Interval LMPs plus other applicable charges will be settled in accordance with Section 11.5.8.1.1. The allocation of the amounts settled in accordance with Section 11.5.1.1 will be settled according to Section 11.5.4.2.

* * *

11.8 Bid Cost Recovery

For purposes of determining the Unrecovered Bid Cost Uplift Payments for each Bid Cost Recovery Eligible Resource as determined in Section 11.8.5 and the allocation of Unrecovered Bid Cost Uplift Payments for each Settlement Interval, the CAISO shall sequentially calculate the Bid Costs, which can be positive (IFM, RUC or RTM Bid Cost Shortfall) or negative (IFM, RUC or RTM Bid Cost Surplus) in the IFM, RUC and the Real-Time Market, as the algebraic difference

between the respective IFM, RUC or RTM Bid Cost and the IFM, RUC or RTM Market Revenues as further described below in this Section 11.8. The RTM Energy Bid Costs and RTM Market Revenues include the FMM Energy Bid Costs. In any Settlement Interval a resource is eligible for Bid Cost Recovery payments pursuant to the rules described in the subsections of Section 11.8 and Section 11.17. Bid Cost Recovery Eligible Resources for different MSS Operators are supply resources listed in the applicable MSS Agreement. All Bid Costs shall be based on Bids as mitigated pursuant to the requirements specified in Section 39.7. Virtual Awards are not eligible for Bid Cost Recovery. Virtual Awards are eligible for make-whole payments due to price corrections pursuant to Section 11.21.2. In order to be eligible for Bid Cost Recovery, Non-Dynamic Resource-Specific System Resources must provide to the CAISO SCADA data by telemetry to the CAISO's EMS in accordance with Section 4.12.3 demonstrating that they have performed in accordance with their CAISO commitments. Scheduling Coordinators for Non-Generator Resources are not eligible to recover Start-Up Costs, Minimum Load Costs, Pumping Costs, Pump Shut-Down Costs, or Transition Costs but are eligible to recover Energy Bid Costs, RUC Availability Payments and Ancillary Service Bid Costs.

11.8.1 CAISO Determination Of Self-Commitment Periods

For the purposes of identifying the periods during which a Bid Cost Recovery Eligible Resource is deemed self-committed and thus ineligible for Start-Up Costs, Transition Costs, Minimum Load Costs, IFM Pump Shut-Down Costs and IFM Pumping Costs, the CAISO derives the Self-Commitment Periods as described below. The CAISO will determine the Self-Commitment Periods for Multi-Stage Generating Resources based on the applicable MSG Configuration. MSS resources designated for Load following are considered to be self-committed if they have been scheduled with non-zero Load following capacity, or are otherwise used to follow Load in the Real-Time. The IFM and RUC Self-Commitment Periods will be available as part of the Day-Ahead Market results provided to the applicable Scheduling Coordinator. The interim RTM Self-Commitment Periods as reflected in the ~~HASP~~RTM will be available as part of the ~~HASP~~RTM results for the relevant Trading Hour as provided to the applicable Scheduling Coordinator. The final RTM Self-Commitment Period is determined ex-post for Settlements purposes. ELS

Resources committed through the ELC Process described in Section 31.7 are considered to have been committed in the IFM Commitment Period for the applicable Trading Day for the purposes of determining BCR settlement in this section 11.8.

* * *

11.8.1.3 Multi-Stage Generating Resource Start-Up, Minimum Load, or Transition Costs

For the settlement of the Multi-Stage Generating Resource Start-Up Cost, Minimum Load Cost, and Transition Cost in the IFM, RUC, and RTM, the CAISO will determine the applicable Commitment Period and select the applicable Start-Up Cost, Minimum Load Cost, and Transition Cost based on the following rules.

(1) In any given Settlement Interval, the CAISO will first apply the following rules to determine the applicable Start-Up Cost, Minimum Load Cost, and Transition Cost for the Multi-Stage Generating Resources. For a Commitment Period in which:

(a) the IFM Commitment Period and/or RUC Commitment Period MSG Configuration(s) are different from the RTM CAISO Commitment Period MSG Configuration, the Multi-Stage Generating Resource's Start-Up Cost, Minimum Load Cost, and Transition Cost will be settled based on the RTM CAISO Commitment Period MSG Configuration Start-Up Cost, and Transition Cost, as described in Section 11.8.4.1. This rule does not apply in cases where there is a CAISO IFM Commitment Period, in which case the Minimum Load Costs will be settled based on the: (i) CAISO IFM Commitment Period MSG Configuration's Minimum Load costs, plus (ii) the positive or negative difference of the CAISO RTM Commitment Period MSG Configuration's Minimum Load Costs and the CAISO IFM Commitment Period MSG Configuration's Minimum Load Costs.

(b) there is a CAISO IFM Commitment Period and/or CAISO RUC Commitment Period in any MSG Configuration and there is also a RTM Self-Commitment Period in any MSG Configuration, the Multi-Stage Generating Resource's Start-Up Cost, Minimum Load Cost, and Transition Cost will be settled based on the CAISO IFM Commitment Period and/or CAISO RUC Commitment Period MSG Configuration(s) Start-Up Cost, Minimum Load Cost, and Transition Cost, as described in Sections 11.8.2.1 and 11.8.3.1, and further determined pursuant to part (2) of this Section below.

(c) the CAISO IFM Commitment Period and/or CAISO RUC Commitment Period MSG Configuration is the same as the CAISO RTM Commitment Period MSG Configuration, the Multi-Stage Generating Resource's Start-Up Cost, Minimum Load Cost, and Transition Cost will be settled based on the CAISO IFM Commitment Period and/or CAISO RUC Commitment Period MSG Configuration(s) Start-Up Cost, Minimum Load Cost, and Transition Cost described in Sections 11.8.2.1 and 11.8.3.1, and further determined pursuant to part (2) of this Section below.

(d) the IFM and RUC Self-Commitment Period MSG Configuration(s) are the same as the CAISO RTM Commitment Period MSG Configuration, then the Multi-Stage Generating Resource's Start-Up Cost, Minimum Load Cost, and Transition Cost will be settled based on the CAISO RTM Commitment Period MSG Configuration Start-Up Cost, Minimum Load Cost, and Transition Cost as described in Section 11.8.4.1.

(2) In any given Settlement Interval, after the rules specified in part (1) above of this Section have been executed, the ISO will apply the following rules to determine whether the IFM or RUC Start-Up Cost, Minimum Load Cost, and Transition Cost apply for Multi-Stage Generating Resources. For a Commitment Period in which:

(a) the IFM Commitment Period MSG Configuration is different from the CAISO RUC Commitment Period MSG Configuration the Multi-Stage Generating Resource's Start-Up Cost, Minimum Load Cost, and Transition Cost will be settled based on the CAISO RUC Commitment Period MSG Configuration Start-Up Cost, Minimum Load Cost, and Transition Cost as described in Section 11.8.3.1.

(b) the CAISO IFM Commitment Period MSG Configuration is the same as the CAISO RUC Commitment Period MSG Configuration, the Multi-Stage Generating Resource's Start-Up Cost, Minimum Load Cost, and Transition Cost will be based on the CAISO IFM Commitment Period MSG Configuration Start-Up Cost, Minimum Load Cost, and Transition Cost as described in Section 11.8.2.1.

* * *

11.8.2.2.1 CAISO IFM Commitment

For any Settlement Interval in a CAISO IFM Commitment Period the IFM Market Revenue for a Bid Cost Recovery Eligible Resource is the algebraic sum of the two products specified below. In the case of a Multi-Stage Generating Resource, the CAISO will calculate the market revenue at the Generating Unit or Dynamic Resource-Specific System Resource level.

(1) The product of the delivered MWh in the relevant Day-Ahead Schedule in that Trading Hour (where for Pumped-Storage Hydro Units and Participating Load operating in the pumping mode or serving Load the MWh is negative), and the

relevant IFM LMP, divided by the number of Settlement Intervals in a Trading Hour.

(2) The product of the IFM AS Award from each accepted IFM AS Bid and the relevant Resource-Specific ASMP, divided by the number of Settlement Intervals in a Trading Hour.

* * *

11.8.4 RTM Bid Cost Recovery Amount

For purposes of determining the RTM Unrecovered Bid Cost Uplift Payments as determined in Section 11.8.5, and for the purposes of allocation of Net RTM Bid Cost Uplift as described in Section 11.8.6.6~~,~~ the CAISO shall calculate the RTM Bid Cost Shortfall or the RTM Bid Cost Surplus as the algebraic difference between the RTM Bid Cost and the RTM Market Revenues for each Settlement Interval. The RTM Bid Costs shall be calculated pursuant to Section 11.8.4.1 ~~and the~~. The RTM Market Revenues shall be calculated pursuant to Section 11.8.4.2. The Energy subject to RTM Bid Cost Recovery is the Instructed Imbalance Energy described in Section 11.5.1, excluding Standard Ramping Energy, Residual Imbalance Energy, Exceptional Dispatch Energy, Derate Energy, Ramping Energy Deviation, Regulation Energy and MSS Load Following Energy regardless of whether the Energy is from the FMM or RTD, and is subject to the application of the Real-Time Performance Metric as described in Section 11.8.4.4 and the Persistent Deviation Metric described in Section 11.17.

* * *

11.8.4.1.4 RTM Pumping Bid Cost

For Pumped-Storage Hydro Units and Participating Load only, the RTM Pumping Bid Cost for the applicable Settlement Interval shall be the Pumping Cost submitted to the CAISO in the ~~HASP or~~ RTM divided by the number of Settlement Intervals in a Trading Hour. The Pumping Cost is negative since it represents the amount the entity is willing to pay to pump or serve Load. The Pumping Cost is included in RTM Bid Cost computation for a Pumped-Storage Hydro Unit and Participating Load committed by the Real-Time Market to pump or serve Load, if it actually operates in pumping mode or serves Load in that Settlement Interval. The RTM

Energy Bid Cost for a Participating Load for any Settlement Interval is set to zero for any Energy consumed in excess of instructed Energy. The RTM Pumping Bid Cost for any Settlement Interval is zero if: (1) the Settlement Interval is included in a RTM Self-Commitment Period for the Bid Cost Recovery Eligible Resource; (2) the Bid Cost Recovery Eligible Resource has been manually dispatched under an RMR Contract or the resource has been flagged as an RMR Dispatch in the Day- Ahead Schedule or the Real-Time Market in that Settlement Interval; (3) the Bid Cost Recovery Eligible Resource is not actually in pumping mode in that Settlement Interval; (4) that Settlement Interval is included in an IFM or RUC Commitment Period; or (5) the Bid Cost Recovery Eligible Resource is committed pursuant to Section 34.~~9~~11.2 for the purpose of performing Ancillary Services testing or pre-commercial operation testing.

* * *

11.8.4.2.1 For each Settlement Interval in a CAISO Real-Time Market Commitment Period, the RTM Market Revenue for a Bid Cost Recovery Eligible Resource is the algebraic sum of the elements listed below in this Section. For Multi-Stage Generating Resources the RTM Market Revenue calculations will be made at the Generating Unit or Dynamic Resource-Specific System Resource level.

(a) The sum of the products of the FMM or RTD Instructed Imbalance Energy (including Energy from Minimum Load of the Bid Cost Recovery Eligible Resource committed in RUC and where for Pumped-Storage Hydro Units and Participating Load operating in the pumping mode or serving Load, the MWh is negative), except Standard Ramping Energy, Residual Imbalance Energy, Exceptional Dispatch Energy, Derate Energy, MSS Load following Energy, Ramping Energy Deviation and Regulation Energy, with the relevant ~~Real-Time Market~~FMM and RTD LMP, for each Dispatch Interval in the Settlement Interval.

(b) The product of the Real-Time Market AS Award from each accepted Real-Time Market AS Bid in the Settlement Interval with the relevant ASMP, divided by the number of fifteen (15)-minute Commitment Intervals in a Trading Hour (4), and prorated to the duration of the Settlement Interval.

~~-~~(c) The relevant tier-1 No Pay charges for that Bid Cost Recovery Eligible Resource in that Settlement Interval.

11.8.4.2.2 For each Settlement Interval in a non-CAISO Real-Time Market Commitment Period, the Real-Time Market Revenue for a Bid Cost Recovery Eligible Resource is subject to the Real-Time Performance Metric and is the algebraic sum of the following:

(a) The sum of the products of the FMM or RTD Instructed Imbalance Energy (excluding the Energy from Minimum Load of Bid Cost Recovery Eligible Resources committed in RUC), except, ~~HASP Self-Scheduled Energy,~~ Standard Ramping Energy, Residual Imbalance Energy, Exceptional Dispatch Energy, Derate Energy, MSS Load Following Energy, Ramping Energy Deviation and Regulating Energy, with the relevant ~~Real-Time~~FMM or RTD Market LMP, for each Dispatch Interval in the Settlement Interval;

(b) The product of the Real-Time Market AS Award from each accepted Real-Time Market AS Bid in the Settlement Interval with the relevant ASMP, divided by the number of fifteen (15)-minute Commitment Intervals in a Trading Hour (4), and prorated to the duration of the Settlement Interval.

(c) The relevant tier-1 No Pay charges for that Bid Cost Recovery Eligible Resource in that Settlement Interval.

* * *

11.8.6.6 Allocation of Net RTM Bid Cost Uplift

The hourly Net RTM Bid Cost Uplift is computed for the Trading Hour as the product of the uplift ratio in Section 11.8.6.3 and the sum over all of the Settlement Intervals of the Trading Hour of any positive Net RTM Bid Cost Uplift after the sequential netting in Section 11.8.6.2. The hourly RTM Bid Cost Uplift is allocated to Scheduling Coordinators, including Scheduling Coordinators for MSS Operators that have elected (a) not to follow their Load, and (b) gross Settlement, in proportion to their Measured Demand plus any ~~HASP~~FMM reductions not associated with valid

and balanced ETCs, TORs or Converted Rights Self-Schedules in the Day-Ahead Market for the Trading Hour. For Scheduling Coordinators for MSS Operators that have elected (a) not to follow their Load, and (b) net Settlement, the hourly RTM Bid Cost Uplift is allocated in proportion to their MSS Aggregation Net Measured Demand plus any ~~HASP~~FMM reductions not associated with valid and balanced ETCs, TORs or Converted Rights Self-Schedules in the Day-Ahead Market. For Scheduling Coordinators of MSS Operators that have elected to follow their Load, the RTM Bid Cost Uplift shall be allocated in proportion to their MSS Net Negative Uninstructed Deviation plus any ~~HASP~~FMM reductions not associated with valid and balanced ETCs, TORs or Converted Rights Self-Schedules in the Day-Ahead Market. Accordingly, each Scheduling Coordinator shall be charged an amount equal to its Measured Demand plus any ~~HASP~~FMM reductions not associated with valid and balanced ETCs, TORs or Converted Rights Self-Schedules in the Day-Ahead Market times the RTM Bid Cost Uplift rate, where the RTM Bid Cost Uplift rate is computed as the Net RTM Bid Cost Uplift amount divided by the sum of Measured Demand plus any ~~HASP~~FMM reductions not associated with valid and balanced ETCs, TORs or Converted Rights Self-Schedules in the Day-Ahead Market across all Scheduling Coordinators for the Trading Hour. Any real-time reductions after HASP results are published to HASP Block Intertie Schedules in response to Dispatch Instructions or real-time scheduling curtailments are not allocated any Net RTM Bid Cost Uplift.

11.9 Inter-SC Trades

11.9.1 Physical Trades

Inter-SC Trades of Energy in the Day-Ahead Market will be settled separately from Inter-SC Trades of Energy in the ~~HASP.~~ RTM. Both the Day-Ahead and ~~HASP~~RTM Inter-SC Trades of Energy will be settled on an hourly basis and the two respective Settlement amounts between the two parties for each market shall net to zero.~~-~~ All MWh quantities of Physical Trades submitted to the CAISO for Settlement in the Day-Ahead Market that are confirmed through the Physical Trade post market confirmation as provided in Section 28.1.6.3 shall be settled at the Day-Ahead LMP at the relevant PNode. ~~-~~All MWh quantities of Physical Trades that are reduced during the Physical Trade post market confirmation shall be settled at the relevant Existing Zone (EZ)

Generation Trading Hub price. -All MWh quantities of Physical Trades submitted to the CAISO for Settlement in the ~~HASP~~RTM that are confirmed through the Physical Trade post market confirmation pursuant to Section 28.6.1.3 shall be settled at the simple average of ~~Dispatch Interval LMP~~the four FMM LMPs at the relevant Pricing Node.- All MWh quantities of Physical Trades submitted for Settlement in ~~HASP~~RTM that are reduced during the Physical Trade post market confirmation shall be settled at the ~~relevant Real-Time~~FMM price for the EZ Generation Trading Hub.

11.9.2 Inter-SC Trades At Aggregated Pricing Nodes

Inter-SC Trades of Energy at Aggregated Pricing Nodes in the Day-Ahead Market will be settled separately from Inter-SC Trades at Aggregated Pricing Nodes in the ~~HASP.~~ RTM. Both the Day-Ahead and ~~HASP~~RTM Inter-SC Trades at Aggregated Pricing Nodes will be settled on an hourly basis and the two respective Settlement amounts between the two parties for each market shall net to zero.- All MWh quantities of Inter-SC Trades at Aggregated Pricing Nodes submitted to the CAISO for Settlement in the Day-Ahead Market shall be settled at the relevant Day-Ahead Aggregated Pricing Node price such as the Existing Zone (EZ) Generation Trading Hub price or LAP price. -All MWh quantities of Inter-SC Trades at Aggregated Pricing Nodes submitted to the CAISO for Settlement in the ~~HASP~~RTM shall be settled at the relevant Real-Time Aggregated Pricing Node price.

* * *

11.10.1.2 Ancillary Services Provided in HASP

The HASP optimization establishes Ancillary Services Awards and prices for Ancillary Services provided from ~~Non-Dynamic System Resources in the~~ HASP~~.~~ Block Intertie Schedules. The CAISO pays Scheduling Coordinators that supply Ancillary Services from ~~Non-Dynamic System Resources~~HASP Block Intertie Schedules an amount equal to the product of the simple average of the ASMPs computed for the four ~~(4) fifteen (15) minute~~FMM intervals ~~of HASP~~ for each Ancillary Service as described in Section 27.1.2, and the quantity of the capacity awarded for the Ancillary Service in the Settlement Period.- The CAISO charges Scheduling Coordinators that receive an Ancillary Service Award or have qualified Self-Provided Ancillary

Services at a Scheduling Point in ~~HASP~~the FMM the simple average of the fifteen (15) minute Marginal Cost of Congestion over the applicable Trading Hour as described in Section 11.10.1.2.1.

11.10.1.2.1 Congestion Charges

If a Scheduling Coordinator, including a Scheduling Coordinator for a Pseudo-Tie of a Generating Unit to the CAISO Balancing Authority Area, receives an Ancillary Services Award or provides a qualified Self- Provided Ancillary Service at a congested Scheduling Point, the CAISO will charge the Scheduling Coordinator for Congestion. The charge for Congestion at such locations is equal to the simple average of the fifteen (15) minute applicable intertie constraint Shadow Price over the applicable Trading Hour at the location of the Ancillary Service Award, multiplied by the quantity of Ancillary Services Award or the capacity of the qualified Self-Provided Ancillary Service for the Settlement Period. No such charge for Congestion will apply when the Scheduling ~~Coordinator's HASP~~ Coordinator provides Ancillary Services ~~Awards and qualified Self-Provided Ancillary Services~~from HASP Block Intertie Schedules at Scheduling Points ~~are provided~~ pursuant to the CAISO Tariff rules that apply to Existing Rights and Transmission Ownership Rights.

* * *

11.10.1.3 Ancillary Services Provided in ~~Real-Time~~the FMM

Suppliers of Ancillary Services from resources awarded in ~~RTUC~~FMM are paid a price equal to one-quarter of the fifteen (15) minute ASMP (in $/MW/h) in each fifteen (15) minute interval of the applicable Trading Hour in which the capacity is procured for each Ancillary Service times the amount of the capacity awarded (MW) for the Ancillary Service in the relevant Ancillary Services Region for the applicable trading hour in which the capacity is procured. For each Ancillary Service, the ASMP is calculated as set forth in Section 27.1.2. Suppliers of Self-Provided Ancillary Services in the Real-Time Market are not eligible to receive payment using the ASMP; rather to the extent the self-provision is qualified it will be valued at the user rate for the relevant service (i.e., will either reduce the Ancillary Services Obligation or receive the user rate if it

exceeds the Scheduling Coordinator's Ancillary Service Obligation) as described in Sections 11.10.2, 11.10.3 and 11.10.4.

* * *

11.10.2 Settlement For User Charges For Ancillary Services

The CAISO shall determine a separate hourly user rate for Regulation Down Reserve, Regulation Up Reserve, Spinning Reserve, and Non-Spinning Reserve purchased for each Settlement Period. The hourly user rates for Regulation Down, Regulation Up, Spinning Reserve, and Non-Spinning Reserve include the cost incurred by the CAISO across the Day-Ahead Market~~, HASP,~~ and the Real-Time Market to procure this service. In computing the user rate for each service the quantity (MW) and costs of any substituting Ancillary Service will be treated as if they are costs and MW associated with the Ancillary Service need they are being used to fulfill. Each rate will be charged to Scheduling Coordinators on a volumetric basis applied to each Scheduling Coordinator's obligation for the specific Ancillary Service concerned which it has not self-provided, as adjusted by any Inter-SC Trades of Ancillary Services.

Each Scheduling Coordinator's obligation for Regulation Down Reserve, Regulation Up Reserve, Spinning Reserve, and Non-Spinning Reserve shall be calculated in accordance with this Section 11.10.2, notwithstanding any adjustment to the quantities of each Ancillary Service purchased by the CAISO in accordance with Section 8.2.3.5. The cost of Voltage Support and Black Start shall be allocated to Scheduling Coordinators as described in Sections 11.10.7 and 11.10.8.

Ancillary Services Obligations for an individual Scheduling Coordinator (before taking into account Self-Provided Ancillary Services) or Inter-SC Trades of Ancillary Services may be negative. Credits for such negative obligations will be in accordance with the rates calculated in this Section 11.10.2, except that a Scheduling Coordinator's credit shall be reduced pro rata to the extent the sum of the negative obligations of all Scheduling Coordinators with the negative Ancillary Services Obligation (before self-provision or Inter-SC Trade) exceeds the obligation of all Scheduling Coordinators with positive obligation net of Self-Provided Ancillary Services, as specified in Section 11.10.5 in any Settlement Period, the net procurement quantity of Regulation

Up, Regulation Down, Spinning Reserve, or Non-Spinning Reserve purchased by the CAISO in the Day-Ahead Market~~, HASP,~~ and the Real-Time Market due to the operation of Section 8.2.3.5 is zero (0), then the user rate for that Ancillary Service type will be zero (0).

With respect to each Settlement Period, in addition to the user rates determined in accordance with this Section 11.10.2, each Scheduling Coordinator shall be charged an additional amount equal to its proportionate share, based on total purchases by Scheduling Coordinators of Regulation Down, Regulation Up, Spinning Reserve, and Non-Spinning Reserve of the amount, if any, by which (i) the total payments to Scheduling Coordinators pursuant to this Section 11.10.2 for the Day-Ahead Market~~, HASP,~~ and the Real-Time Market, exceed (ii) the total amounts charged to Scheduling Coordinators pursuant to this Section 11.10.2, for the Day-Ahead Market~~, HASP,~~ and the Real-Time Market.~~-~~ If total amounts charged to Scheduling Coordinators exceed the total payments to Scheduling Coordinators, each Scheduling Coordinator will be refunded its proportionate share, based on total purchases by Scheduling Coordinators of Regulation Down, Regulation Up, Spinning Reserve, and Non-Spinning Reserve.

~~-~~With respect to each Settlement Period, in addition to Ancillary Service charges at the applicable user rates determined in accordance with this Section 11.10.2, each Scheduling Coordinator shall be charged additional neutrality adjustment amounts for each Ancillary Service type pursuant to Sections 11.10.2.4, 11.10.2.2.3, 11.10.3.3, and 11.10.4.3 and a neutrality adjustment amount for upward Ancillary Service types pursuant to Section 11.14.

* * *

11.10.4.1 Hourly User Rate Non-Spinning Reserves

The hourly user rate for Non-Spinning Reserves is calculated as the ratio of: i) the sum of the portion of the Non-Spinning Reserve Cost used to meet the Non-Spinning requirement and a portion of the Regulation Up and Spinning Reserve costs that can substitute for Non-Spinning Reserve and ii) the Net Procurement quantity of Non-Spinning Reserves by the CAISO ($/MW). ~~-~~The CAISO's Non-Spinning Reserve Cost includes the costs associated with any

Regulation Up Reserve or Spinning Reserve capacity used as Non-Spinning Reserve under Section 8.2.3.5.

The CAISO's Non-Spinning Reserve Cost is equal to: (i) the revenues paid to the suppliers of the total awarded Non-Spinning Reserve capacity in the Day-Ahead Market and Real-Time Market, minus, (ii) the payments rescinded due to either the failure to conform to CAISO Dispatch Instructions or the unavailability of the Non-Spinning Reserves under Section 8.10.8. The Net Procurement of Non-Spinning Reserves is equal to: (i) the amount (MWs) of total awarded Non-Spinning Reserve capacity in the Day- Ahead Market and Real-Time Market, minus, (ii) the Non-Spinning Reserve capacity associated with payments rescinded pursuant to any of the provisions of Section 8.10.8. The amount (MW) of awarded Non-Spinning Reserve capacity includes the amounts (MW) associated with any Regulation Up Reserve or Spinning Reserve capacity used as Non-Spinning Reserve under Section 8.2.3.5.

* * *

11.10.9 Settlements Of Rescission Of Payments For AS Capacity

The rescission of payments for Ancillary Services for Undispatchable, Unavailable, and Undelivered Capacity applies to Ancillary Services that are awarded in the Day-Ahead Market~~,~~ ~~HASP,~~ or Real-Time Market and the rescission will be the weighted average of the Ancillary Service Marginal Prices (ASMPs) and Ancillary Services Award amounts for a resource across the Day-Ahead Market~~, HASP,~~ and Real- Time Market. For Self-Provided Ancillary Service capacity that becomes Undispatchable Capacity, Unavailable Capacity, or Undelivered Capacity, the rescission of Ancillary Services self-provision in the Day-Ahead Market~~, HASP,~~ and Real-Time Market reduces the relevant Scheduling Coordinator's effective Ancillary Services self-provision in the Ancillary Services cost allocation, effectively resulting in a charge back at the relevant Ancillary Services rate. The rescission of payments in this Section 11.10.9 shall not apply to a capacity payment for any particular Ancillary Service if the weighted average Ancillary Service Marginal Price (ASMP) is less than or equal to zero (0).

* * *

11.12.1 ~~Uninstructed Energy By~~ **Settlement of PIRP Protective Measures**

The provisions in this Section 11.12.1 and its subsections will be in effect as of the day this Section becomes effective and the CAISO will implement these measures no later than twelve months after the effective date of this section.

11.12.1.1 Hourly Settlement

Scheduling Coordinators that represent Participating Intermittent Resources that have been qualified for PIRP Protective Measures pursuant to Section 4.8.3 will be subject to the following Settlement requirements. The CAISO will first settle the market outcomes for the Participating Intermittent Resources subject to PIRP Protective Measures consistent with the rules specified in Section 11.

~~Uninstructed Imbalance Energy associated with deviations by a Participating Intermittent Resource shall be settled as provided in this Section 11.12.1 for every Settlement Period in which such Participating Intermittent Resource meets the scheduling requirements established in the Eligible Intermittent Resources Protocol in Appendix Q. Initially, the Uninstructed Imbalance Energy associated with deviations by a Participating Intermittent Resource shall be settled in accordance to Section 11.5.2. However, if the above-referenced scheduling requirements for Participating Intermittent Resources are met, then charges (payments) for Uninstructed Imbalance Energy during such Settlement Periods shall be reversed at the end of the Trade Month and settled as specified in Section 11.12.1. The net Uninstructed Imbalance Energy in each Settlement Interval shall be assigned to a deviation account specific to each Participating Intermittent Resource. The net balance in each deviation account at the end of each calendar month shall be paid (or charged) to the Scheduling Coordinator for the associated Participating Intermittent Resource at the average price specified in Section 34.19.2.5.~~

11.12.1.2 PIRP Protective Measures Monthly Adjustments

At the end of the month, the CAISO will calculate the PIRP Protective Measures monthly resettlement, which it will base on the forecast established for the Participating Intermittent Resource 90 minutes prior to the applicable Trading Hour. For each month the CAISO will calculate the PIRP Protective Measures Settlement Amount as the total of: (1) the sum of the

product of the 90 minute MWh amounts, for each hour of the month multiplied by the simple average of the RTD LMP for the applicable Trading Hour; and (2) the product of (a) the monthly netted MWh quantities under PIRP Protective Measures, which is the sum of the hourly differences between the ninety (90) minute MWh amounts and the Participating Intermittent Resource's 5-minute metered MWhs, and (b) the resource's monthly weighted average RTD LMP, where the weights are the metered Generation quantities associated with each RTD LMP. If the Scheduling Coordinator submits an Economic Bid or Self-Schedule to the Real-Time Market, the resource will be disqualified from PIRP Protective Measures for the remaining term that the PIRP Protective Measures are otherwise intended to apply. The disqualification will be in effect as of the Trading Day for which the Scheduling Coordinators submitted the Economic Bid. The CAISO will take the necessary steps to implement that disqualification and will make any necessary Settlement adjustments consistent with the change in status. In addition, for the intervals in which the Scheduling Coordinator submitted an Economic Bid for a the resource while it was still qualified as a resource subject to PIRP Protective Measures, the resource will not be eligible for any Bid Cost Recovery related payments for such Economic Bids.

11.12.1.3 Use of Inter-Scheduling Coordinator Trades for Energy

To the extent a Participating Intermittent Resource that is subject to PIRP Protective Measures is contractually required to make use of the CAISO's Inter-Scheduling Coordinator Trade for Energy to effectuate payment transfers with its contractual counterparty, the Scheduling Coordinator may select a flag in its Master File to indicate its election to settle of any Physical or Converted Physical Inter-Scheduling Coordinator Trades for Energy submitted for the Participating Intermittent Resource at the Participating Intermittent Resource location as follows; the Inter-Scheduling Coordinator Trades will settle at the hourly simple average of the RTD LMP of the PNode at the affected PIR location. Financial Inter-Scheduling Coordinator Trades for Energy will not be eligible for such treatment.

11.12.2 ~~———~~Allocation Of ~~Participating Intermittent Resources~~PIRP Protective Measures Costs/Revenues

~~The charges (~~For each month, the CAISO will calculate the difference between the charges and payments~~) for Uninstructed Imbalance Energy that would have been calculated if the Settlement Interval deviations by~~ made to the Scheduling Coordinator for each Participating Intermittent Resource ~~were priced at the appropriate Resource-Specific Settlement Interval LMP shall be assigned to a monthly balancing account for all Participating Intermittent Resources in the CAISO Balancing Authority Area. The balance in such account at the end of each month shall be netted against the aggregate payments (charges) by Scheduling Coordinators on behalf of Participating Intermittent Resources.~~under its Settlement as specified in Sections 11, and the PIRP Protective Measurement resettlement amounts. The ~~resulting balance shall be assigned~~CAISO will charge or credit the differences to ~~each~~the Scheduling Coordinator and will allocate a corresponding credit or charge to all Scheduling Coordinators in ~~the same~~ proportion ~~that such~~to each Scheduling Coordinator's aggregate Net Negative Uninstructed Deviations in that month ~~bears~~relative to the aggregate Net Negative Uninstructed Deviations for all Scheduling Coordinators in the CAISO Balancing Authority Area in that month.

* * *

11.12.3.3 Participating Intermittent Resource Export Fee

A Participating Intermittent Resource Export Fee will be levied to Participating Intermittent Resources that have elected for PIRP Protective Measures in accordance with Section 5.3 of Appendix Q and Schedule 4 of Appendix F.

11.12.4 [Not Used] ~~Price For Uninstructed Deviations~~

~~Uninstructed Deviations associated with each Participating Intermittent Resource in a Scheduling Coordinator's portfolio shall be settled as provided in Section 34.19.2.5 at the monthly weighted average Dispatch Interval LMP, where the weights are the metered Generation quantities associated with each Dispatch Interval LMP.~~

* * *

11.17.1.2.1 Rule 1

If ~~three (3~~six (6) or fewer Settlement Intervals out of the previous ~~twelve (12~~twenty-four (24) Settlement Intervals are flagged pursuant to the rules in Section 11.17.1.1, then: (a) the RTM

Energy Bid Costs will be based on the applicable Energy Bid price as specified in Section 11.8.4.1.5, and (b) Residual Imbalance Energy will be settled based on the reference hour Energy Bid as specified in Section 11.5.5.

11.17.1.2.2 Rule 2

If ~~four (4~~seven (7) or more Settlement Intervals of the previous ~~twelve (12)~~ twenty-four (24) Settlement Intervals are flagged as exceeding the Persistent Deviation Metric Threshold, then for all the previous ~~twelve (12~~twenty-four(24) Settlement Intervals in the two-hour window: (a) the RTM Energy Bid Costs specified in Section 11.8.4.1.5 (i) for Optimal Energy above the Day-Ahead Scheduled Energy will be based on the lesser of the applicable Default Energy Bid price, the applicable Energy Bid price, as mitigated, or the applicable FMM or RTD Locational Marginal Price, and (ii) for Optimal Energy below the Day-Ahead Scheduled Energy ~~will be based on~~ the greater of the applicable Default Energy Bid price, the applicable Energy Bid price, as mitigated, or the applicable FMM or RTD Locational Marginal Price; and (b) Residual Imbalance Energy as specified in Section 11.5.5 (i) for Residual Imbalance Energy above the Day-Ahead Scheduled Energy will be based on the lesser of the applicable Default Energy Bid price, the relevant Energy Bid Price, as mitigated, or the applicable RTD Locational Marginal Price, and (ii) ~~for~~ Residual Imbalance Energy below the Day-Ahead Scheduled Energy will be based on the greater of the applicable Default Energy Bid price, the relevant Energy Bid Price, or the applicable RTD Locational Marginal Price.

* * *

11.21.1 CAISO Demand and Exports

If the CAISO corrects an LMP in the upward direction pursuant to Section 35 that impacts Demand in the Day-Ahead Market and the ~~HASP~~FMM such that either a portion of or the entire cleared CAISO Demand or export Economic Bid curve becomes uneconomic, then the CAISO will calculate and apply the Price Correction Derived LMP for settlement of CAISO Demand and exports in Section 11.2.1.2, 11.2.3, 11.2.1.4 and 11.4.1. The CAISO shall not calculate and apply a Price Correction Derived LMP for settlement of exports that are part of a Schedule that results from Bids submitted in violation of Section 30.5.5. The CAISO will calculate a Price

Correction Derived LMP for each affected CAISO Demand and exports as follows: ~~-~~the total cleared MWhs of CAISO Demand or exports in the Day-Ahead Schedule or ~~HASP Intertie~~FMM Schedule, as applicable, multiplied by the corrected LMP, minus the make-whole payment amount, all of which is divided by the total cleared MWhs of CAISO Demand or export in the Day-Ahead Schedule or ~~HASP Intertie~~FMM Schedule, as applicable. The make-whole payment amount will be calculated on an hourly basis determined by the area between the Scheduling Coordinator's CAISO Demand or Export Bid curve and the corrected LMP, which is calculated as the MWhs for each of the cleared bid segments in the Day-Ahead Schedule or ~~HASP Intertie~~FMM Schedule for the affected resource, multiplied by the maximum of zero or the corrected LMP minus the bid segment price.~~-~~ For the purpose of this calculation, the CAISO will not factor in a make-whole payment amount for Self-Scheduled CAISO Demand or exports. ~~-~~Any non-zero amounts in revenue collected as a result of the application of the Price Correction Derived LMP will be captured through the calculation of the IFM Congestion Charge reflected in Section 11.2.4.1 and the allocation of non-zero amounts of the sum of Imbalance Energy, Uninstructed Imbalance Energy, and Unaccounted for Energy in accordance with Section 11.5.4.

* * *

11.25.1 Compensation

All resources identified as resolving the Flexible Ramping Constraint in the applicable RTUC interval are awarded Flexible Ramping Constraint capacity and will be compensated for such capacity for each RTUC interval, whether or not the Flexible Ramping Constraint is binding, limited by the quantity of Flexible Ramping Constraint requirements set by the CAISO operators as follows: The Scheduling Coordinator is paid the product of the (1) upward MW of capacity identified to satisfy the constraint, multiplied by 0.25 hours, and (2) Flexible Ramping Constraint Derived Price calculated for each applicable fifteen-minute ~~RTUC~~FMM interval as described further in this Section 11.25.1. Payment to resources will be rescinded as set forth in Section 11.25.2. For each applicable fifteen-minute ~~RTUC~~FMM interval, the Flexible Ramping Constraint Derived Price is equal to the lesser of: 1) $800/MWh; or 2) the greater of: (a) zero (0), or (b) the Real-Time ASMP for Spinning Reserves for the applicable fifteen-minute ~~RTUC~~FMM interval; or

(c) the Flexible Ramping Constraint Shadow Price minus seventy-five (75) percent of the maximum of (i) zero (0), or (ii) the Real-Time System Marginal Energy Cost, calculated as the simple average of the System Marginal Energy Cost for each of the three five-minute ~~Dispatch Interval System Marginal energy costs~~RTD intervals in the applicable fifteen-minute ~~RTUC~~FMM interval. The Shadow Price of the binding Flexible Ramping Constraint represents the reduction of the total Energy and Ancillary Services procurement cost associated with a marginal change of that constraint, which is equal to zero (0) if the Flexible Ramping Constraint is not binding. All costs associated with payments made pursuant to this Section 11.25 are allocated to all Scheduling Coordinators pursuant to the requirements set forth in Section 11.25.3.

11.25.2 Rescission of Payment for Non-Performance

Payments to Scheduling Coordinators are rescinded for the quantity of MWs of undelivered Flexible Ramping Constraint capacity determined as the hourly sum of the Settlement Interval amounts calculated as the minimum of: 1) the Flexible Ramping Constraint capacity identified as having contributed to the relief of the Flexible Ramping Constraint, or 2) the maximum of (a) zero (0), or (b) the difference between (i) the absolute value of ~~sum of~~ the negative ~~Tier 1~~ UIE ~~and negative Tier 2 UIE, which are both as defined in Section 11.5.2,~~ and (ii) the upward MWs identified as Undelivered Ancillary Services Capacity as required in Section 11.10.9.3. The rescinded amounts will be based on the product of the: 1) MWs quantities to be rescinded determined as described in this Section 11.~~2~~5.2; and 2) hourly Flexible Ramping Constraint price determined as the weighted average of the four fifteen-minute Flexible Ramping Constraint Derived Prices derived as described in Section 11.25.1.

* * *

11.29.5.3 Data Files

Settlement Statements relating to each Scheduling Coordinator, CRR Holder, Black Start Generator or Participating TO shall be accompanied by data files of supporting information that includes the following for each Settlement Period of the Trading Day:

(a) the aggregate quantity (in MWh) of Energy supplied or withdrawn by the Scheduling Coordinator Metered Entities represented by the Scheduling Coordinator;

(b) the aggregate quantity (in MW) and type of Ancillary Services capacity provided or purchased;

(c) the relevant prices that the CAISO has applied in its calculations;

(d) details of the scheduled quantities of Energy and Ancillary Services accepted by the CAISO in the Day-Ahead Market and the ~~Hour-Ahead Market~~RTM;

(e) details of Imbalance Energy and penalty payments;

(f) details of the CRR Payments or CRR Charges, and any payments or charges associated with the CRR Auctions; and

(g) detailed calculations of all fees, charges and payments allocated among Scheduling Coordinators and each Scheduling Coordinator's share.

* * *

11.29.17.2.1 Methodology for Allocating Payment Default Amounts

Except as set forth in Section 11.29.17.2.2, each payment default amount allocated to CAISO Creditors through a shortfall allocation pursuant to Section 11.29.17.1 and that remains unpaid by the defaulting Scheduling Coordinator or CRR Holder will be allocated on the next practicable Invoices to the Default-Invoiced SCIDs to which the percentage shares calculated pursuant to Section 11.29.17.2.7 for the current calendar quarter apply, excluding the CAISO Debtor that has not paid the payment default amount, pursuant to the following methodology:

(a) Twenty (20) percent of the payment default amount will be allocated to the Default-Invoiced SCIDs in proportion to the net amounts that were payable in each applicable calendar quarter (and averaged within such calendar quarter) to the Default-Invoiced SCIDs over the applicable Default Look-Back Periods. For Market Participants subject to Default Election option 1, these net amounts will be calculated on an SCID-by-SCID basis. For Market Participants that are

eligible for and have chosen Default Election option 2, these net amounts will be calculated by consolidating all of the data for the applicable SCIDs, recognizing any offsetting effect of an individual SCID's positive or negative dollar amount in the consolidated total.

(b) Thirty (30) percent of the payment default amount will be allocated to the Default-Invoiced SCIDs in proportion to the sum of the absolute values of the dollar amounts shown on their Invoices payable or receivable in each applicable calendar quarter (and averaged within such calendar quarter) over the applicable Default Look-Back Periods, after excluding dollar amounts shown on the Invoices for payments and charges for GMC, RMR, and Wheeling Access Charge costs, and after excluding the billing of Access Charges and the payment of Transmission Revenue Requirements to Participating Transmission Owners. For Market Participants subject to Default Election option 1, the sum of the absolute values of the dollar amounts shown on their Invoices payable or receivable in each applicable calendar quarter will be calculated on an SCID-by-SCID basis. For Market Participants that are eligible for and have chosen Default Election option 2, the absolute values of the net sum of the dollar amounts shown on their Invoices payable or receivable in each applicable calendar quarter will be calculated by consolidating all of the data for the applicable SCIDs, recognizing any offsetting effect of an individual SCID's positive or negative dollar amount in the consolidated total.

(c) Fifty (50) percent of the payment default amount will be allocated to the Default-Invoiced SCIDs in proportion to the largest of the following five (5) amounts calculated in MWh for every month in each applicable calendar quarter (and averaged within such calendar quarter) for each Default-Invoiced SCID over the applicable Default Look-Back Periods:

(1) Cleared Day-Ahead Schedules to supply Energy, plus Day-Ahead

Ancillary Services Awards and qualified Self-Provided Ancillary Services, plus scheduled supply obligation for Ancillary Services (including imports but excluding RUC Schedules), plus Virtual Supply Awards;

(2) Metered Generation, plus Real-Time Interchange Import Schedules, plus Real-Time Ancillary Services Awards and qualified Self-Provided Ancillary Services, plus ~~HASP~~FMM Ancillary Services Awards and qualified Self-Provided Ancillary Services, plus Real-Time supply obligation for Ancillary Services;

(3) Cleared Day-Ahead Schedules for Demand (including Demand served by Pumped-Storage Hydro Units and exports) multiplied by one-hundred three (103) percent to reflect Transmission Losses, plus scheduled demand obligation for Ancillary Services, plus Virtual Demand Awards;

(4) Metered Load multiplied by one-hundred three (103) percent to reflect Transmission Losses, plus Real-Time Interchange Export Schedules, plus Real-Time demand obligation for Ancillary Services; or

(5) The greater of (A) the quantity of CRRs acquired in CRR Auctions or transferred through the Secondary Registration System (excluding CRRs acquired in CRR Allocations) or (B) Inter-SC Trades of Energy.

For Market Participants subject to Default Election option 1, each of the five (5) amounts calculated in MWh for every month in each applicable calendar quarter (and averaged within such calendar quarter) will be calculated on an SCID-by-SCID basis. ~~-~~For Market Participants that are eligible for and have chosen Default Election option 2, each of the five (5) amounts calculated in MWh for every month in each applicable calendar quarter (and averaged within such calendar quarter) will be calculated by consolidating all of the data for the applicable SCIDs.

* * *

11.31 ~~HASP~~ Intertie Schedules Decline Charges

The Decline Potential Charge ~~– Imports~~ shall apply to ~~any~~Intertie transactions as discussed belowbelow. The Decline Potential Charge does not apply to FMM Schedules of Economic Bids,

Dynamic Transfers, and Variable Energy Resources located outside the CAISO Balancing Authority Area that have been qualified to use the forecast of their output produced by the CAISO as specified in Section 4.8.2.1.2.

(a) HASP Block Intertie Schedules: Any HASP Block Intertie Schedule for an Energy import when the HASP Block Intertie Schedule is not delivered for any reason (with no exceptions based on the circumstances of a particular failure to deliver~~).~~), to the extent the decline is made prior to the start of the applicable FMM interval. The Decline Potential Charge – Exports shall apply to any HASP Block Intertie Schedule for an Energy export when the HASP Block Intertie Schedule is not delivered for any reason (with no exceptions based on the circumstances of a particular failure to deliver~~).~~), to the extent the decline is made prior to the start of the applicable FMM interval. The Decline Potential Charge will not apply if the decline is made after the applicable E-tag deadline, as defined in Section 30.6.2.

(b) Economic Hourly Block Bid with Intra-Hour Option: Imports and exports accepted in an HASP Block Intertie Schedule that are incremental to Day-Ahead Schedules are subject to the Decline Potential Charge to the extent the decline is made prior to the start of the applicable FMM interval. The Decline Potential Charge will not apply if the decline is made after the applicable E-tag deadline, as defined in Section 30.6.2. To the extent the incremental import or export schedule in HASP is curtailed through the FMM, for the 15-minute FMM interval in which the resource follows the CAISO Dispatch Instructions will not be subject to the Decline Potential Charge.

(c) Variable Energy Resources outside CAISO Balancing Authority Area Using Own Forecast: Imports from Variable Energy Resources using their own forecast are subject to the Decline Potential Charge to the

extent the resource over-forecasts over the month as discussed below. For each Trading Hour, the CAISO compares the maximum 15-minute FMM Schedule (that is based on the forecast submitted 37.5 minutes prior to flow) to the maximum 15-minute advisory schedule from the Hour-Ahead Scheduling Process (based upon the hourly forecast received 75 minutes prior to flow) and calculates the differences between the two. These hourly differences are summed over the month. If the maximum advisory schedule exceeds the actual financially binding schedule by the relevant threshold over the course of the month, the Decline Potential Charge applies.

(d) Decline Potential Charge: For any Settlement Interval, the Decline Potential Charge – Imports or Decline Potential Charge – Exports, as the case may be, shall equal the MWh quantity of the import or export not delivered multiplied by the greater of $10/MWh or fifty percent (50%) of the ~~HASP Intertie~~FMM LMP. The Decline Potential Charge – Imports and Decline Potential Charge – Exports will be calculated for each HASP Block Intertie Schedule or VER Self-Schedule that is not delivered, provided that only the Decline Monthly Charge – Imports and Decline Monthly Charge – Exports shall be payable by the Scheduling Coordinator as described in Section 11.31.1.

11.31.1 Decline Monthly Charge – Imports

The Decline Monthly Charge – Imports shall be applied to each Scheduling Coordinator on the Settlement Statements issued for the last Trading Day of each Trading Month, and shall be the sum of the Scheduling Coordinator's Decline Potential Charges – Imports for each Settlement Period during that Trading Month multiplied by a ratio. The ratio will represent the portion of the Scheduling Coordinator's declined HASP Block Intertie Schedules for Energy imports or the VER Self-Schedules that exceed during the Trading Month the applicable exemption threshold ~~during the Trading Month~~described in Section 11.31.1 and Section 11.31.2.

(a) The ratio will be calculated as follows:

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

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

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

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

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

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

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

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

11.31.2 Decline Monthly Charge – Exports

The Decline Monthly Charge – Exports shall be applied to each Scheduling Coordinator on the Settlement Statements issued for the last Trading Day of each Trading Month, and shall be the sum of the Scheduling Coordinator's Decline Potential Charges – Exports for each Settlement Interval during that Trading Month multiplied by a ratio. The ratio will represent the portion of the

Scheduling Coordinator's declined HASP Block Intertie Schedules for Energy exports that exceed the applicable exemption threshold during the Trading Month.

(a) The ratio will be calculated as follows:

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

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

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

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

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

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

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

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

* * * *

11.32 Measures to Address Intertie Scheduling Practices

The CAISO will take the following actions regarding Schedules that clear the Day-Ahead Market at the Interties and that are wholly or partially reversed ~~in the HASP~~through a FMM Schedule:

(i) The CAISO will charge the Scheduling Coordinator the positive difference between the Day-Ahead Market price and the ~~HASP price~~FMM LMP applicable to any imports that clear the Day-Ahead Market and are reduced ~~in~~through a Bid to the ~~HASP for which~~RTM if the Scheduling Coordinator ~~has failed~~either: (a) fails to submit an E-Tag or E-Tags consistent with the Scheduling Coordinator's Day-Ahead Schedule and WECC scheduling criteria~~.~~; or (b) withdraws the E-Tag or E-Tags prior to forty-five (45) minutes before the Trading Hour.

(ii) The CAISO will charge the Scheduling Coordinator the positive difference between the ~~HASP price~~FMMLMP and the Day-Ahead Market ~~price~~LMP applicable to any exports that clear the Day-Ahead Market and are reduced ~~in~~through a Bid to the ~~HASP for which~~RTM if the Scheduling Coordinator ~~has failed~~either: (a) fails to submit an E-Tag or E-Tags consistent with the Scheduling Coordinator's Day-Ahead Schedule and WECC scheduling criteria; or (b) withdraws the E-Tag or E-Tags prior to forty-five (45) minutes before the Trading Hour.

(iii) The CAISO will treat any reduction by a Scheduling Coordinator to a Day-Ahead import or export Schedule ~~in~~through a Bid to the ~~HASP~~RTM as a Virtual Award for purposes of adjusting CRR Revenue pursuant to Section 11.2.4.6 if the Scheduling Coordinator submits Schedules on behalf of or is a CRR Holder.

(iv) For any import Schedule that clears the Day-Ahead Market which a Scheduling Coordinator reduces ~~in~~through a Bid to the ~~HASP~~RTM, such reduced quantities will be subject to the allocation of Net RTM Bid Cost Uplift as set forth in Section 11.8.6.6.

(v) The provisions of this Section 11.32 will not apply to Schedules that clear the Day-Ahead Market at the ~~Interties~~Scheduling Points and that a Scheduling Coordinator wholly or partially reverses ~~in~~through a Bid to the ~~HASP~~RTM to the extent such Schedules are valid and balanced ETC, TOR, or Converted Rights Self-Schedules in the Day-Ahead Market.

11.33 Settling Revenue from Schedule Sourcing/Sinking in Same BAA

The import portion of any Schedule resulting from Bids submitted in violation of Section 30.5.5 will be settled at the lower of the: (a) LMP of the Scheduling Point for the import portion of the Schedule in the market in which the import portion of the Schedule was awarded; or (b) LMP of the Scheduling Point for the export portion of the Schedule in the market in which the export portion of the Schedule was awarded. Such settlement will occur irrespective of whether the import and export were scheduled in the same market or are split between the Day-Ahead Market and ~~HASP~~the Real-Time Market.

* * *

16.4.5 TRTC Instructions Content

TRTC Instructions will include the following information at a minimum and such other information as the CAISO may reasonably require the Participating TO to provide to enable the CAISO to carry out its functions under the CAISO Tariff, Operating Procedures and Business Practice Manuals:

(1) A unique Contract Reference Number for each source and sink combination applicable to the Existing Contract (i.e., the CRN that will be assigned by the CAISO and communicated to the Participating TO that references a single Existing Contract or a set of interdependent Existing Contracts for each source and sink combination);

(2) Whether the instruction can be exercised independent of the CAISO's day-to-day involvement ("Yes/No");

(3) Name of an operational single point of contact for instructions and a 24-hour a day telephone number for the Participating TO contact for Existing Contract issues or the agreed upon party;

(4) Name(s) and number(s) of Existing Contract(s) that are represented by the unique CRN;

(5) The following information as stored in the Master File: (a) the applicable Point(s) of Receipt and Point(s) of Delivery); (b) for each Point of Receipt, the resource names for the physical resources as the eligible sources (eligible physical sources include Generating Units and System Resources), and for each Point of Delivery, the resource names for the physical resources as the eligible sinks (eligible physical sinks include Load PNodes, Custom Load Aggregation Points and System Resources); (c) for each physical source or sink, the maximum Existing Rights capacity (MW) that can be scheduled as an Existing Right under the Existing Contract; and (d) for each physical source and sink, the Scheduling Coordinator(s) and their Business Associate Identification (BAID) that is(are) eligible to submit ETC Self-Schedules utilizing these sources and sinks;

(6) Names of the party(ies) to the Existing Contract(s);

(7) The Scheduling Coordinator BAID that is entitled to the Settlement of reversal of Congestion Charges;

(8) Type(s) of service rights by the holder of the Existing Rights, by type of service (firm, conditional firm, or non-firm), with priorities for firm and conditional firm transmission services and maximum amounts of service rights in MW;

(9) Instructions for the allowable timeframes at which the ETC Self-Schedules and ETC Self-Schedule changes may be submitted to the CAISO, which include whether the Scheduling Coordinator may submit ETC Self-Schedules or ETC Self-Schedule changes: (a) into the DAM~~;~~ ~~(~~;(b) into the ~~HASP and the~~ RTM; (c) after the close of submitting Bids into the ~~HASP and the~~ RTM, but before twenty (20) minutes before the applicable Trading Hour of the Trading Day; and (d) at or after ~~-~~twenty (20) minutes before the applicable Trading Hour of the Trading Day; in addition, the TRTC Instructions may also include any additional comments and restrictions on the submission time of ETC Self-Schedules and ETC Self-Schedule changes;

(10) Term or service period(s) of the Existing Contract(s);

(11) Any special procedures that would require the CAISO to implement curtailments in any manner different from pro rata reduction of the transfer capability of the transmission line; any such TRTC Instructions submitted to the CAISO must be clear, unambiguous, and not require the CAISO to make any judgments or interpretations as to the meaning intent, results, or purpose of the curtailment procedures or the Existing Contract and the section of the Existing Contract that provides this right for reference, otherwise, they will not be accepted by the CAISO;

(12) The forecasted usage patterns for each Existing Contract for the upcoming annual period of the annual CRR release processes as well as for the upcoming monthly period of the monthly CRR release processes, which will consist of hourly MWh data over the whole year for those resources that will use the Existing Contract; this information will be considered by the CAISO in managing its accounting for usage of Existing Rights in the release of CRRs; this information shall not be used by the CAISO to validate ETC Self-Schedules when submitted by Scheduling Coordinators and therefore shall not affect the Existing Rights holder's ability to utilize its rights under the Existing Contract;

(13) Whether or not the Existing Contract provides for the right to self-provide Ancillary Services; and

(14) Specification of any contract requirements in the ETC that warrants special consideration in the implementation of the physical rights under the ETC.

* * *

16.5 Treatment Of Existing Contracts For Transmission Service

The CAISO will accommodate Existing Rights, so that the holders of Existing Rights will receive the same priorities (in scheduling, curtailment, assignment and other aspects of transmission system usage) to which they are entitled under their Existing Contracts.

In addition, scheduling deadlines and operational procedures associated with Existing Rights will be honored by the CAISO, provided such information is explicitly included in the TRTC Instructions. The CAISO will accommodate and honor Existing Rights as follows:

(1) For Existing Rights that permit Interchange Schedule changes over Scheduling Points with other Balancing Authority Areas, the CAISO will reserve transmission capacity equal to the Existing Rights transmission capacity and make a corresponding adjustment in its determination of ATC. For Existing Rights that permit Interchange Schedule changes

after the Market Close of the Day-Ahead Market, the CAISO will reserve transmission capacity equal to the unscheduled ETC amount of transmission capacity for that Scheduling Point.

(2) For Existing Rights within the CAISO Balancing Authority Area, the CAISO will not set-aside capacity associated with the Existing Rights transmission capacity.

(3) In the ~~HASP~~RTM, the CAISO will give valid ETC Self-Schedules priority over other non-ETC Day-Ahead Schedules and ~~HASP~~RTM Bids.~~-~~ In the event of a reduction in capacity on the transmission path associated with the Existing Right, the CAISO will honor the Existing Rights priority in accordance with this Section 16.

(4) When the Existing Contract permits, the CAISO will allow the holder of Existing Rights to make changes to the scheduled amounts of Supply after the submission of HASP ETC Self-Schedules in accordance with the TRTC Instructions established for such changes.~~-~~ The CAISO will, as necessary, redispatch non-ETC resources to accommodate valid ETC Self-Schedule changes in Real-Time.

(5) All contractual provisions that have been communicated to the CAISO in writing in accordance with this Section 16 by the parties to the Existing Contracts, shall be honored by the CAISO and the parties to the Existing Contracts and shall be implemented by the CAISO in accordance with the terms and conditions of the relevant Existing Contracts so notified.

16.5.1 System Emergency Exceptions

As set forth in Section 4.2.1, all Market Participants, including Scheduling Coordinators, Utility Distribution Companies, Participating TOs, Participating Generators (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area), Participating Loads, Demand Response Providers, Balancing Authorities (to the extent the agreement between the Balancing Authority and the CAISO so provides), and MSS Operators within the CAISO Balancing Authority

Area and all System Resources must comply fully and promptly with CAISO Dispatch Instructions and operating orders, unless such operation would impair public health or safety. The CAISO will honor the terms of Existing Contracts, provided that in a System Emergency and circumstances in which the CAISO considers that a System Emergency is imminent or threatened, holders of Existing Rights must follow CAISO operating orders even if those operating orders directly conflict with the terms of Existing Contracts, unless such operating orders are inconsistent with the terms of an agreement between the CAISO and a Balancing Authority. ~~-~~In the event of a conflict between the CAISO Tariff and an agreement between the CAISO and a Balancing Authority, the agreement will govern. ~~-~~For this purpose CAISO operating orders to shed Load shall not be considered as an impairment to public health or safety. ~~-~~This section does not prohibit a Scheduling Coordinator from modifying its Bid or re-purchasing Energy in the ~~HASP or~~ Real-Time Market.

* * *

16.9.1 Scheduling Deadlines

Those holders of Existing Rights who have Existing Rights as reflected in the TRTC Instructions that allow scheduling after the close of the Day-Ahead Market may submit ETC Self-Schedules for the use of those rights by the deadline for the Market Close for ~~the HASP~~RTM. Submission of schedule changes beyond the Market Close for ~~the HASP~~RTM that are permitted ~~by the~~ pursuant to the terms of the applicable ETC ~~will~~, shall not be ~~treated as provided~~deemed to be an unbalanced ETC Self-Schedule for the purposes of Settlement, consistent with the ETC and TOR Self-Schedule Settlement treatment described in Section ~~33.3.~~11.5.7..

* * *

16.11 Inter-Balancing Authority Area ETC Self-Schedule Bid Changes

Changes to ETC Self-Schedules that occur during the CAISO's Real-Time Market that involve changes to CAISO Balancing Authority Area imports or exports with other Balancing Authority Areas (that is, inter-Balancing Authority Area changes to ETC Self-Schedules) will be allowed and will be recorded by the CAISO based upon notification received from the Scheduling Coordinator representing the holder of the Existing Rights. ~~-~~The Scheduling Coordinator

representing the holder of the Existing Right must notify the CAISO of any such changes to external import/export in submitted ETC Self-Schedules. The Scheduling Coordinator representing the holder of the Existing Right must notify the CAISO of Real-Time Market changes to external import/export Interchange Schedules in submitted ETC Self-Schedules, by telephone. The timing and content of any such notification must be consistent with the TRTC Instructions previously submitted to the CAISO by the Responsible PTO. The CAISO will manually adjust or update the ~~HASP Intertie~~FMM Schedule for the Scheduling Coordinator to conform with the other Balancing Authority Area's net ETC Self-Schedule in Real-Time, and the notifying Scheduling Coordinator will be responsible for and manage any resulting Energy imbalance. These Imbalance Energy deviations will be priced and charged to the Scheduling Coordinator representing the holder of Existing Rights in accordance with the ~~Real-Time~~FMM LMP.

* * *

17.1.4 TRTC Instructions Content

TRTC Instructions will include the following information at a minimum and such other information as the CAISO may reasonably require the Non-Participating TO holder of a TOR to provide to enable the CAISO to carry out its functions under the CAISO Tariff, Operating Procedures and Business Practice Manuals:

(1) A unique Contract Reference Number for each source and sink combination applicable to the TOR (i.e., the CRN that will be assigned by the CAISO and communicated to the Non-Participating TO that references a single TOR or a set of interdependent TORs for each source and sink combination);

(2) Whether the instruction can be exercised independent of the CAISO's day-to-day involvement ("Yes/No");

(3) Name of an operational single point of contact for instructions and a 24- hour a day telephone number for the Non-Participating TO contact for TOR issues or the agreed upon party;

(4) Name(s) and number(s) of TOR(s) that are represented by the unique

CRN;

(5) The following information, as stored in the Master File: (a) the applicable Point(s) of Receipt and Point(s) of Delivery); (b) for each Point of Receipt, the resource names for the physical resources as the eligible sources (eligible physical sources include Generating Units and System Resources), and for each Point of Delivery, the resource names for the physical resources as the eligible sinks (eligible physical sinks include Load PNodes, Custom Load Aggregation Points and System Resources); (c) for each physical source or sink, the maximum capacity (MW) that can be scheduled as a TOR; and (d) for each physical source and sink, the Scheduling Coordinator(s) and their Business Associate Identification (BAID) that is (are) eligible to submit TOR Self-Schedules utilizing these sources and sinks;

(6) Names of the party(ies) holding the TOR(s) and the parties to any agreements applicable to the TORs;

(7) The Scheduling Coordinator BAID that is entitled to the Settlement of reversal of Congestion Charges;

(8) Amount of TORs, in maximum MW, that may be utilized under the relevant TRTC Instructions;

(9) Instructions for the allowable timeframes at which the TOR Self-Schedules and TOR Self-Schedule changes may be submitted to the CAISO, which include whether the Scheduling Coordinator may submit TOR Self-Schedules or TOR Self-Schedule changes: (a) into the DAM; (b) into the ~~HASP and the~~ RTM; (c) after the close of submitting Bids into ~~the HASP and~~ the RTM, but before twenty (20) minutes before the applicable Trading Hour of the Trading Day; and (d) at or after twenty (20) minutes before the applicable Trading Hour of the Trading Day; in addition, the Non-Participating TO may also provide any additional

comments and restrictions on the submission time of TOR Self-Schedules and TOR Self-Schedule changes;

(10) Term of ownership interest in the TOR(s) and of any agreements applicable to the TOR(s);

(11) Any special procedures that would require the CAISO to implement curtailments in any manner different than pro rata reduction of the transfer capability of the transmission line; any such instructions submitted to the CAISO must be clear, unambiguous, and not require the CAISO to make any judgments or interpretations as to the meaning, intent, results, or purpose of the curtailment procedures or of any applicable Existing Contract, otherwise, they will not be accepted by the CAISO; and

(12) Whether or not the TOR provides the right to self-provide Ancillary Services.

* * *

17.2 Treatment Of TORs

The CAISO will accommodate TORs, so that the holders of TORs will receive the same priorities (in scheduling, curtailment, assignment and other aspects of transmission system usage) to which they are entitled under any applicable Existing Contracts or other agreements pertaining to the operation of their TORs.

In addition, scheduling deadlines and operational procedures associated with TORs will be honored by the CAISO, provided such information is explicitly included in the TRTC Instructions. The CAISO will accommodate and honor TORs as follows:

(1) The CAISO will reserve transmission capacity equal to the TOR transmission capacity and make a corresponding adjustment in its determination of ATC. The CAISO will not limit parallel flow from flowing on TOR transmission capacity consistent with the redispatch provisions of Section 17.2(3), just as the CAISO does not limit TOR Self-

Schedules from flowing on non-TOR transmission. There shall be no compensation for parallel flow for either the CAISO or the TOR holder.

(2) In the ~~HASP~~RTM, the CAISO will give valid TOR Self-Schedules priority over other non-TOR Day-Ahead Schedules and ~~HASP~~RTM Bids. In the event of a reduction in capacity on the transmission path associated with the TOR, the CAISO will honor the TOR priority in accordance with this Section 17.

(3) The CAISO will allow the holder of a TOR to make changes to the scheduled amounts of supply after the submission of HASP TOR Self-Schedules in accordance with the TRTC Instructions established for such changes. The CAISO will, as necessary, redispatch non-TOR resources to accommodate valid TOR Self-Schedule changes in Real-Time.

(4) The CAISO will allow the holder of a TOR to self-provide Ancillary Services, which will include the ability of the holder of a TOR to import Ancillary Services at Scheduling Points with the CAISO.

(5) The submission of a TOR Self-Schedule change that is authorized pursuant to an applicable existing agreement shall not affect the application of the IFM Congestion Credit or the ~~HASP and~~ RTM Congestion Credit, and the IFM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules or the RTM Marginal Cost of Losses Credit for Eligible TOR Self-Schedules for a TOR Self-Schedule that satisfies the applicable requirements of Sections 17.4.1 and 17.5.

17.2.1 System Emergency Exceptions

As set forth in Section 4.2.1, all Market Participants, including Scheduling Coordinators, Utility Distribution Companies, Participating TOs, Participating Generators(which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area), Participating Loads, Demand Response Providers, Balancing Authorities (to the extent the agreement between the Balancing

Authority and the CAISO so provides), and MSS Operators within the CAISO Balancing Authority Area and all System Resources must comply fully and promptly with the CAISO's Dispatch Instructions and operating orders, unless such operation would impair public health or safety.

The CAISO will honor the terms of TORs, provided that in a System Emergency and circumstances in which the CAISO considers that a System Emergency is imminent or threatened, to enable the CAISO to exercise its responsibilities as Balancing Authority in accordance with Applicable Reliability Criteria, holders of TORs must follow CAISO operating orders even if those operating orders directly conflict with the terms of applicable Existing Contracts or any other contracts pertaining to the TORs, unless such operating orders are inconsistent with the terms of an agreement between the CAISO and a Balancing Authority. In the event of a conflict between the CAISO Tariff and an agreement between the CAISO and a Balancing Authority, the agreement will govern. For this purpose CAISO operating orders to shed Load shall not be considered as an impairment to public health or safety. This section does not prohibit a Scheduling Coordinator from modifying its Bid or re-purchasing Energy in the ~~HASP or~~ RTM.

* * *

17.4.1 Scheduling Deadlines

Holders of TORs may submit TOR Self-Schedules for the use of those rights by the deadline for the Market Close for the ~~HASP~~RTM.

* * *

17.6 Inter-Balancing Authority Area TOR Self-Schedule Bid Changes

Changes to TOR Self-Schedules that occur during the CAISO's Real-Time Market that involve changes to CAISO Balancing Authority Area imports or exports with other Balancing Authority Areas (that is, inter-Balancing Authority Area changes to TOR Self-Schedules) will be allowed and will be recorded by the CAISO based upon notification received from the Scheduling Coordinator representing the holder of the TOR. The Scheduling Coordinator representing the holder of the TOR must notify the CAISO of any such changes to external import/export in

submitted TOR Self-Schedules. -The Scheduling Coordinator representing the holder of the TOR must notify the CAISO of Real-Time Market changes to external import/export Interchange Schedules in submitted TOR Self-Schedules, by telephone. -The timing and content of any such notification must be consistent with the TRTC Instructions previously submitted to the CAISO by the Non-Participating TO. -The CAISO will manually adjust or update the ~~HASP Intertie~~FMM Schedule for the Scheduling Coordinator to conform with the other Balancing Authority Area's net TOR Self-Schedule in Real-Time, and the notifying Scheduling Coordinator will be responsible for and manage any resulting Energy imbalance.- These Imbalance Energy deviations will be priced and charged to the Scheduling Coordinator representing the holder of the TOR in accordance with the ~~Real-Time~~FMM LMP.

* * *

27 CAISO Markets And Processes

In the Day-Ahead and Real-Time time frames the CAISO operates a series of procedures and markets that together comprise the CAISO Markets Processes. In the Day-Ahead time frame, the CAISO conducts the Market Power Mitigation (MPM) process, the Integrated Forward Market (IFM) and the Residual Unit Commitment (RUC) process. In the Real-Time time frame, the CAISO does the following: 1)accepts the Economic Bids and Self-Schedules used in the Real-Time Market procedures, 2) conducts the MPM process~~,~~ for the ~~Hour-Ahead Scheduling Process (~~RTM, 3) accepts and awards HASP~~),~~ Block Intertie Schedules for Energy and Ancillary Services, 4) provides HASP Advisory Schedules for Energy and Ancillary Services for Bids that do not create a HASP Block Intertie Schedule, 5) conducts the Real-Time Unit Commitment (RTUC), 6) conducts the Short-Term Unit Commitment (STUC), 7) conducts the ~~Real-Time Unit Commitment (RTUC)~~Fifteen Minute Market (FMM), and 8) conducts the five-minute Real-Time Dispatch (RTD). ~~The~~ As appropriate, the CAISO Markets Processes utilize transmission and Security Constrained Unit Commitment and dispatch algorithms in conjunction with a Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 to optimally commit, schedule and Dispatch resources and determine marginal prices for Energy, Ancillary Services and RUC Capacity. Congestion Revenue Rights are available and entitle holders of such instruments to a stream of hourly payments or

charges associated with revenue the CAISO collects or pays from the Marginal Cost of Congestion component of hourly Day-Ahead LMPs. Through the operation of the CAISO Markets Processes the CAISO develops Day-Ahead Schedules, Day-Ahead AS Awards and RUC Schedules, , HASP ~~Advisory Schedules, HASP~~ Block Intertie Schedules for Energy and AS Awards, HASP Advisory Schedules, FMM Energy Schedules, and FMM Ancillary Services Awards, Real-Time AS Awards and Dispatch Instructions to ensure that sufficient supply resources are available in Real-Time to balance Supply and Demand and operate in accordance with Reliability Criteria.

* * *

27.1.1 Locational Marginal Prices For Energy

As further described in Appendix C, the LMP for Energy at any PNode is the marginal cost of serving the next increment of Demand at that PNode consistent with existing Transmission Constraints and the performance characteristics of resources, also considering, among other things, Energy Bid Curves. The LMP at any given PNode is comprised of three cost components: the System Marginal Energy Cost (SMEC); Marginal Cost of Losses (MCL); and Marginal Cost of Congestion (MCC). The IFM calculates LMPs for each Trading Hour of the next Trading Day. The ~~HASP, which is conducted hourly for scheduling Non-Dynamic System Resources and exports for the subsequent Trading Hour,~~FMM calculates distinct financially binding fifteen-minute LMPs ~~(HASP Intertie LMPs) for that Trading Hour. The simple average~~ for each of the four fifteen-minute ~~LMPs for the applicable Trading Hour computed at each Scheduling Point produces hourly LMPs for HASP Settlement of Energy at that Scheduling Point.~~intervals within a Trading Hour. The Real-Time Dispatch runs every five (5) minutes throughout each Trading Hour and calculates five-minute LMPs for the next Dispatch Interval. The CAISO uses the ~~Resource-Specific Settlement Interval~~FMM or RTD LMPs for Settlements of the Real-Time Market.~~-~~ In the event that a Pricing Node becomes electrically disconnected from the market model during a CAISO Market run, the LMP, including the SMEC, MCC and MCL, at the closest electrically connected Pricing Node will be used as the LMP at the affected location.

* * *

27.1.2.1 Ancillary Service Marginal Prices – Sufficient Supply

As provided in Section 8.3, Ancillary Services are procured and awarded through the IFM~~, HASP and the Real-Time Market.~~ and the FMM, and the CAISO also accepts and awards HASP Block Intertie Schedules for Ancillary Services in HASP. Ancillary Services awarded through HASP are made financially binding in the FMM. The IFM calculates hourly Day-Ahead Ancillary Service Awards and establishes Ancillary Service Marginal Prices (ASMPs) for the accepted Regulation Up, Regulation Down, Spinning Reserve and Non-Spinning Reserve Bids. The IFM co-optimizes Energy and Ancillary Services subject to resource, network and regional constraints. In the HASP, the CAISO ~~procures~~accepts and awards Ancillary Services from ~~Non-Dynamic System Resources~~HASP Block Intertie Schedules for the next Trading Hour as described in Section ~~33.7~~34.2. The CAISO calculates the ~~HASP~~ price for the settlement of Ancillary Services ~~price~~ accepted and awarded in HASP based on the FMM ASMP as described herein and further described in Section ~~33.8. In the Real-Time Market, the RTUC~~34.4. The FMM process that is performed every fifteen (15) minutes establishes fifteen (15) minute Ancillary Service Schedules, Awards, and prices for the upcoming quarter of the given Trading Hour. ASMPs are determined by first calculating Shadow Prices of Ancillary Services for each Ancillary Service type and the applicable Ancillary Services Regions. The Ancillary Services Shadow Prices are produced as a result of the co-optimization of Energy and Ancillary Services through the IFM~~, HASP,~~ and the Real-Time Market, subject to resource, network, and requirement constraints. The Ancillary Services Shadow Prices represent the marginal cost of the relevant binding regional constraints at the optimal solution, or the reduction of the combined Energy and Ancillary Service procurement cost associated with a marginal relaxation of that constraint. If the constraint for an Ancillary Services Region is not binding, the corresponding Ancillary Services Shadow Price in the Ancillary Services Region is zero (0). During periods in which supply is sufficient, the ASMP for a particular Ancillary Service type and Ancillary Services Region is then the sum of the Ancillary Services Shadow Prices for the specific type of Ancillary Service and all the other types of Ancillary Services for which the subject Ancillary Service can substitute, as described in Section 8.2.3.5, for the given Ancillary Service Region and all the other Ancillary Service Regions that include that given Ancillary Service Region. During periods in which supply is insufficient, the

ASMP for a particular Ancillary Service type and Ancillary Services Region will reflect the Scarcity Reserve Demand Curve Values set forth in Section 27.1.2.3.

27.1.2.2 Opportunity Cost in ASMP

The Ancillary Services Shadow Price, which, as described above, is a result of the Energy and Ancillary Service co-optimization, includes the ~~forgone~~foregone opportunity cost of the marginal resource, if any, for not providing Energy or other types of Ancillary Services the marginal resource is capable of providing in the relevant market. The ASMPs determined by the IFM or ~~RTUC~~FMM optimization process for each resource whose Ancillary Service Bid is accepted will be no lower than the sum of (i) the Ancillary Service capacity Bid price submitted for that resource, and (ii) the foregone opportunity cost of Energy in the IFM or ~~RTUC~~FMM for that resource. The foregone opportunity cost of Energy for this purpose is measured as the positive difference between the IFM or ~~RTUC~~FMM LMP at the resource's Pricing Node and the resource's Energy Bid price. If the resource's Energy Bid price is higher than the LMP, the opportunity cost measured for this calculation is $0. If a resource has submitted an Ancillary Service Bid but no Energy Bid and is under an obligation to offer Energy in the Day-Ahead Market (e.g. a non-hydro Resource Adequacy Resource), its Default Energy Bid will be used, and its opportunity cost will be calculated accordingly. If a resource has submitted an Ancillary Service Bid but no Energy Bid and is not under an obligation to offer Energy in the Day-Ahead Market, its Energy opportunity cost measured for this calculation is $0 since it cannot be dispatched for Energy. For ~~Non-Dynamic System Resources that receive~~ Self-Scheduled Hourly Block Bids for Ancillary Services ~~Awards~~awarded in HASP, the opportunity cost measured for this purpose is $0 because, as provided in Section ~~33.7~~34.2.3**,** the CAISO cannot Schedule Energy in HASP from the Energy Bid under the same Resource ID as the submitted Ancillary Service Bid.

* * *

27.2.2.2 Real-Time Market LAP Prices

~~The Hourly Real-Time LAP Price is computed as described in Section 11.5.2.2. The weights used for calculating the Hourly Real-Time LAP Price at the time the RTM runs will not exclude the Demand specified in Sections 27.2.1 and 30.5.3.2. The weights used for calculating Hourly Real-~~

~~Time LAP Price used for Settlements will be calculated based on Meter Data and will appropriately exclude the Demand specified in Sections 27.2.1 and 30.5.3.2. Hourly Real-Time LAP Price are further adjusted for Settlements purposes as described in Section 11.5.2.2.~~

~~**27.2.2.2.1**~~ The Default LAP Hourly Real-Time Prices and the Custom LAP Hourly Real-Time Prices are calculated as described below and in Section 11.5.2.2.

27.2.2.2.1 Default LAP Pricing

The ~~Real-Time~~FMM and RTD Default LAP Price for a fifteen-minute FMM interval and five minute Dispatch Interval is~~ -~~ the price as produced by the ~~Real-Time Market~~FMM and RTD optimization ~~run~~runs, respectively, based on the distribution of system Load at the constituent Pricing Nodes within the applicable Default LAP and is determined by the effectiveness of the Load within the Default LAP in relieving a Transmission Constraint within the effectiveness threshold as specified in Section 27.3.4.6.~~ -~~ The Default LAP Hourly Real-Time Price is then determined for Settlement purposes as further described in Section 11.5.2.2.

27.2.2.2.2 Custom LAP Pricing

The ~~RTM~~FMM and RTD LAP ~~Price~~Prices for Settlement of Demand at Custom LAPs for a given fifteen-minute FMM interval and five minute Dispatch interval ~~is~~are calculated as a Load-weighted average of the individual ~~RTM~~FMM and RTD LMPs at the PNodes within the Custom LAP, respectively, where the weights are~~ -~~ calculated based on Meter Data.~~ -~~ The Custom LAP Hourly Real-Time ~~LAP~~ Price is then determined for Settlement purposes as further described in Section 11.5.2.2.

* * *

27.4.1 Security Constrained Unit Commitment

The CAISO uses SCUC to run the MPM process associated with the DAM~~, the HASP,~~ and the RTM. SCUC is conducted over multiple varying intervals to commit and schedule resources as follows: (1) in the Day-Ahead time frame, to meet Demand reflected in Bids submitted in the Day-Ahead Market and considered in the MPM process and IFM, and to procure AS in the IFM; (2) to meet the CAISO Forecast ~~of~~Of CAISO Demand in the RUC, HASP, STUC and ~~RTUC~~ FMM, and in the MPM process utilized in the HASP and RTM; and (3) to procure any incremental AS in the

~~HASP and~~ RTM~~.~~ . In the Day-Ahead MPM, IFM and RUC processes, the SCUC commits resources over the twenty-four (24) hourly intervals of the next Trading Day. In the ~~RTUC~~FMM, which runs every fifteen (15) minutes and commits resources for the RTM, the SCUC optimizes over a number of 15-minute intervals corresponding to the Trading Hours for which the Real-Time Markets have closed. The Trading Hours for which the Real-Time Markets have closed consist of (a) the Trading Hour in which the applicable run is conducted and (b) all the fifteen-minute intervals of the entire subsequent Trading Hour. In the HASP, which ~~is a special run of the RTUC that~~ runs once per hour, the SCUC ~~schedules Non-Dynamic System Resources~~; 1) accepts and ~~exports~~awards HASP Block Intertie Schedules for ~~the applicable subsequent~~ Energy and Ancillary Services, respectively; 2) provides HASP Advisory Schedules to Economic Hourly Block Bids with Intra-Hour Option that will change for economic reasons at most once in the Trading Hour; and 3) provides HASP Advisory Schedules to all other participants in the RTM. In the STUC, which runs once an hour, the SCUC commits resources over the last fifteen (15) minutes of the imminent Trading Hour and the entire next four Trading Hours. The CAISO will commit Extremely Long Start Resources, for which commitment in the DAM does not provide sufficient time to Start-Up and be available to supply Energy during the next Trading Day as provided in Section 31.7.

* * *

27.4.3.1 Scheduling Parameters for Transmission Constraint Relaxation

In the IFM, the internal Transmission Constraint scheduling parameter is set to $5000 per MWh for the purpose of determining when the SCUC and SCED software in the IFM ~~and the HASP~~ will relax an internal Transmission Constraint rather than adjust Supply or Demand bids or Non-priced Quantities as specified in Sections 31.3.1.3, 31.4 and 34.~~10~~12 to relieve Congestion on the constrained facility. This scheduling parameter is set to $1,500 per MWh for the ~~Real-Time Dispatch.~~RTM. The effect of this scheduling parameter value is that if the optimization can re-dispatch resources to relieve Congestion on a Transmission Constraint at a cost of $5000 per MWh or less for the IFM ~~and HASP~~ (or $1,500 per MWh or less for the ~~Real-Time Dispatch~~RTM), the Market Clearing software will utilize such re-dispatch, but if the cost exceeds $5000 per MWh

in the IFM ~~and HASP~~ (or $1,500 per MWh ~~or less~~ for the ~~Real-time Dispatch~~RTM) the market software will relax the Transmission Constraint. The corresponding scheduling parameter in RUC is set to $1250 per MWh.

* * *

27.5.1 ~~Network Models used in CAISO Markets~~

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

~~27.5~~.1.~~1~~ Base Market Model used in the CAISO Markets

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

Certain external loops are modeled, which allows the CAISO to increase the accuracy of the Congestion Management process. Resources are modeled at the appropriate network Nodes.

The pricing Location (PNode) of a Generating Unit generally coincides with the Node where the relevant revenue quality meter is connected or corrected, to reflect the point at which the Generating Unit is connected to the CAISO Controlled Grid. The Dispatch, Schedule, and LMP of a Generating Unit refers to a PNode, but the Energy injection is modeled in the Base Market Model for network analysis purposes at the corresponding Generating Unit's physical interconnection point), taking into account any losses in the non-CAISO Controlled Grid leading to the point where Energy is delivered to CAISO Controlled Grid. Based on the Base Market Model, the market models used in each of the CAISO markets incorporate physical characteristics needed for determining Transmission Losses and model Transmission Constraints within the CAISO Balancing Authority Area, which are then reflected in the Day-Ahead Schedules, AS Awards and RUC Awards, ~~HASP Intertie~~FMM Schedules, Dispatch Instructions, and LMPs resulting from each CAISO Markets Process.~~–~~ The Dispatch, Schedule, and LMP of a Dynamic System Resource or Pseudo-Tie of a Generating Unit to the CAISO Balancing Authority Area refer to a PNode, or Aggregated Pricing Node, if applicable, of the resource at its physical location in the external transmission systems that are modeled in the Base Market Model, subject to the modeling of Transmission Losses in the portions of the FNM and exclusion of such Transmission Losses' effects on the LMPs that are external to the CAISO Balancing Authority Area described in this Section 27.5.1.1. The LMP price thus associated with a Dynamic System Resource or Pseudo-Tie Generating Unit will be used for Settlement of Energy and will include the Marginal Cost of Congestion and Marginal Cost of Losses components of the LMP to that Dynamic System Resource or Pseudo-Tie Generating Unit point, excluding losses and congestion external to the CAISO Balancing Authority Area, in accordance with this Section 27.5.1.1. Further, in formulating the market models for the ~~HASP, STUC, RTUC, and RTD~~RTM processes, the Real-Time power flow parameters developed from the State Estimator are applied to the Base Market Model.

27.5.2 Metered Subsystems

The FNM includes a full model of MSS transmission networks used for power flow calculations and Congestion Management in the CAISO Markets Processes. Transmission Constraints (i.e. circuit ratings, thermal ratings, etc.) within the MSS, or at its boundaries, that are modeled in the Base Market Model shall be monitored but not enforced in operation of the CAISO Markets. If overloads are observed in the forward markets, are internal to the MSS or at the MSS boundaries, and are attributable to MSS operations, the CAISO shall communicate such events to the Scheduling Coordinator for the MSS and coordinate any manual Re-dispatch required in Real-Time. If, independent of the CAISO, the Scheduling Coordinator for the MSS is unable to resolve Congestion internal to the MSS or at the MSS boundaries in Real-Time, the CAISO will use Exceptional Dispatch Instructions on resources that have been bid into the ~~HASP and~~ RTM to resolve the Congestion. The costs of such Exceptional Dispatch will be allocated to the responsible MSS Operator. Consistent with Section 4.9, the CAISO and MSS Operator shall develop specific procedures for each MSS to determine how Transmission Constraints will be handled.

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27.5.6 Management & Enforcement of Constraints in the CAISO Markets

The CAISO operates the CAISO Markets through the use of a market software system that utilizes various information including the Base Market Model, the State Estimator, submitted Bids including Self-Schedules, Generated Bids, and Transmission Constraints, including Nomograms and Contingencies transmission and generation Outages. The market model used in each of the CAISO Markets is derived from the most current Base Market Model available at that time. To create a more relevant time-specific network model for use in each of the CAISO Markets, the CAISO will adjust the Base Market Model to reflect Outages and derates that are known and applicable when the respective CAISO Market will operate, and to compensate for observed discrepancies between actual real-time power flows and flows calculated by the market software. Through this process the CAISO creates the market model to be used in each Day-Ahead Market~~, HASP,~~ and each process of the Real-Time Market.

The CAISO will manage the enforcement of Transmission Constraints, including Nomograms and Contingencies, consistent with good utility practice, to ensure, to the extent possible, that the market model used in each market accurately reflects all the factors that contribute to actual Real-Time flows on the CAISO Controlled Grid and that the CAISO Market results are better aligned with actual physical conditions on the CAISO Controlled Grid. In operating the CAISO Markets, the CAISO may take the following actions so that, to the extent possible, the CAISO Market solutions are feasible, accurate, and consistent with good utility practice:

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

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

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

and reliable market solution.

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

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

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

* * *

27.7.3 Constrained Output Generators In The IFM

In the IFM, resources electing COG status are modeled as though they are not constrained and can operate flexibly between zero (0) and their PMax. ~~-~~A COG is eligible to set IFM LMPs based on its Calculated Energy Bid in any Settlement Period in which a portion of its output is needed as a flexible resource to serve Demand. ~~-~~A COG is not eligible for recovery of Minimum Load Costs or BCR in the IFM due to the conversion of its Minimum Load Cost to an Energy Bid and its treatment by the IFM as a flexible resource. ~~-~~A COG is eligible for Start-Up Cost recovery based on its Commitment Period as determined in the IFM, RUC, ~~HASP,~~ STUC or RTUC.

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27.7.5 Constrained Output Generators In The Real-Time Market

A COG that can be started up and complete its Minimum Run Time within a five-hour period can be committed by the STUC. A COG that can be started up within the applicable RTUC run as described in Section 34.~~2~~3 can be committed by the RTUC. The RTD will dispatch a COG up to its PMax or down to zero (0) to ensure a feasible Real-Time Dispatch. The COG is eligible to set the RTM LMP in any Dispatch Interval in which a portion of its output is needed to serve Demand, not taking into consideration its Minimum Run Time constraint. For the purpose of making this determination and setting the RTM LMP, the CAISO treats a COG as if it were flexible with an infinite Ramp Rate between zero (0) and its PMax, and uses the COG's Calculated Energy Bid. In any Dispatch Interval where none of the output of a COG is needed as a flexible resource to serve Demand, the CAISO shall not dispatch the unit. In circumstances in which the output of the COG is not needed as a flexible resource to serve Demand, but the unit nonetheless is online as a result of a previous commitment or Dispatch Instruction by the CAISO, the COG is eligible for Minimum Load Cost compensation.

* * *

27.9 Non-Generator Resources MWh Constraints

THIS TARIFF SECTION WILL BECOME EFFECTIVE ON NOVEMBER 27, 2012.

The CAISO will observe Non-Generator Resources' MWh constraints in the IFM as part of the co-optimization unless the resources are using Regulation Energy Management. The CAISO will observe Non-Generator Resources' MWh constraints in RUC as part of the co-optimization unless the resources are using Regulation Energy Management. The CAISO will observe Non-Generator Resources' MWh constraints in Real-Time Unit Commitment and FMM as part of the co-optimization unless the resources are using Regulation Energy Management. The CAISO will observe Non-Generator Resources' MWh constraints in Real-Time Dispatch, including constraints of resources using Regulatory Energy Management

* * *

27.10 Flexible Ramping Constraint

The CAISO may enforce a Flexible Ramping Constraint in the ~~HASP, RTUC, STUC, and RTED.~~ RTM. Any flexible Dispatch capacity constrained to be available as a result of the Flexible Ramping Constraint in ~~RTUC~~RTM will come from capacity that is not designated to provide Regulation or Operating Reserves, and will not offset the required procurement of those Regulation or Operating Reserves in RTUC. To the extent a resource incurs an opportunity cost for not providing Energy or Ancillary Services in the ~~RTUC~~FMM or RTD interval as a result of a binding Flexible Ramping Constraint, all resources resolving that Flexible Ramping Constraint will be compensated pursuant to Section 11.25. In the FMM or RTD the resources identified as resolving the Flexible Ramping Constraint in the corresponding RTUC run will be the only resources used to resolve the Flexible Ramping Constraint enforced in FMM or RTD. The Flexible Ramping Constraint can be satisfied only by committed online dispatchable Generating Units, Participating Load, and Proxy Demand Response resources with ramping capability for which a Scheduling Coordinator has submitted Economic Bids for Energy for the applicable Trading Hour, and Dynamic System resources as specified below. This constraint cannot be satisfied by System Resources that are not Dynamic System Resources. Dynamic System Resources can become eligible to participate in relieving the Flexible Ramping Constraint if the Scheduling Coordinator scheduling that Resource can demonstrate that it has firm transmission service to the CAISO Balancing Authority Area intertie that allows the resource to deliver additional Energy in Real-Time, consistent with the requirements of Section 1.5 of the Dynamic Scheduling Protocol in Appendix M. This Dynamic System Resource must demonstrate that the Dynamic System Resource has acquired sufficient firm transmission to support the total quantity of Energy and Ancillary Services offered in the Real-Time Market by submitting an E-Tag with a transmission profile that reflects the necessary transmission reservation(s) outside the CAISO Balancing Authority Area.

Procurement of Flexible Ramping Constraint capacity from Dynamic System Resources is limited by the available capacity in Real-Time for the applicable interval on the applicable intertie transmission constraint with which the Dynamic System Resource is associated. The

quantity of the flexible ramping capacity for each applicable CAISO Market run will be determined by CAISO operators using tools that estimate the: 1) expected level of imbalance variability; 2) uncertainty due to forecast error; and 3) differences between the hourly, fifteen (15) minute average and historical five (5) minute Demand levels.

* * *

28.1.2 Availability Of Inter-SC Trades Of Energy

The CAISO allows Inter-SC Trades of Energy at individual PNodes of Generating Units and unique Aggregated Pricing Nodes of Physical Scheduling Plants within the CAISO Balancing Authority Area and at Aggregated Pricing Nodes that are either defined Trading Hubs or Default LAPs. The CAISO does not allow Inter-SC Trades of Energy at Scheduling Points. The CAISO allows submission of Inter-SC Trades of Energy in the DAM and ~~the HASP~~RTM. Inter-SC Trades of Energy submitted for the DAM are settled at the hourly DAM LMP at the applicable Aggregated Pricing Nodes or PNodes. Inter-SC Trades of Energy submitted in the ~~HASP~~RTM are settled hourly based on the simple average of the ~~RTM Dispatch Interval~~four FMM LMPs at the applicable Aggregated Pricing Nodes or PNodes.

28.1.3 Submission Of Inter-SC Trades Of Energy

A Scheduling Coordinator may submit Inter-SC Trades of Energy that it intends to have settled based on DAM LMPs at any time during the Day-Ahead Inter-SC Trade Period and may submit Inter-SC Trades of Energy for a particular hour that it intends to have settled based on the simple average of the ~~RTM Dispatch Interval~~four FMM LMPs during that hour at any time during the ~~HASP~~RTM Inter-SC Trade Period.

* * *

28.1.5 General Validation Rules For Inter-SC Trades

For all Inter-SC Trades of Energy the CAISO shall verify that the Scheduling Coordinators for the Inter-SC Trade of Energy mutually agree on the quantity, location, time period, and CAISO Market (for pricing purposes, i.e., DAM or ~~RTM~~FMM) for settling the Inter-SC Trade of Energy. Any individual Inter-SC Trade of Energy that is deemed invalid by the CAISO due to inconsistencies between the trading Scheduling Coordinators on these terms will be rejected.

The CAISO will notify trading Scheduling Coordinators within a reasonable time if their Inter-SC Trades of Energy fail these general validation rules as described in the Business Practice Manuals.

28.1.6 Validation Procedures For Physical Trades

All Inter-SC Trades at PNodes and all Inter-SC Trades of Physical Scheduling Plants at their unique Aggregated Pricing Nodes will be subject to validation procedures as specified in this Section. Physical Trades can occur at any individual Generating Unit's PNode or a Physical Scheduling Plant's Aggregated Pricing Node provided the Physical Trade satisfies the CAISO's Physical Trades validation procedures described herein. The Scheduling Coordinators must demonstrate that the trade is supported (directly or through an Inter-SC Trade of Energy with another Scheduling Coordinator) by a Day-Ahead Schedule or ~~HASP Advisory~~FMM Schedule for a Generating Unit or Physical Scheduling Plant at the same location for the Inter-SC Trade of Energy at a level greater than or equal to the amount of the Inter-SC Trade of Energy. The CAISO's validation procedures for Physical Trades include three components: (1) Physical Trade submittal screening, (2) Physical Trade pre-market validation, and (3) Physical Trade post-market confirmation.

* * *

28.1.6.2 Physical Trade Pre-Market Validation

The purpose of the pre-market validation is to determine whether the total MWh quantity of all submitted Physical Trades at a PNode of an individual Generating Unit or the Aggregated Pricing Node of a Physical Scheduling Plant exceeds the resource's Energy Bid MWh. Pre-market validation is performed on all Physical Trades that pass the submittal screening set forth in Section 28.1.6.1. Scheduling Coordinators are notified within a reasonable time of their Physical Trades status as the CAISO conducts the pre-market validation to indicate, at a minimum, whether the Physical Trade is currently "conditionally valid", "conditionally invalid", or "conditionally modified." These Physical Trade notices are preliminary and subject to change until the final pre-market validation at the close of the relevant Inter-SC Trade Period. A Physical Trade with a "conditionally valid" or "conditionally modified" status may be rendered "conditionally

invalid" due to the actions of the Scheduling Coordinators to that Physical Trade or by other trading activities that are linked to the Generating Unit identified for the relevant Physical Trade whenever the quantities specified in the relevant Inter-SC Trades cannot be supported by the underlying Bid. Scheduling Coordinators can use these status notices to make modifications to complete or correct invalid Physical Trades. The CAISO also performs cyclic pre-market validation prior to the close of the relevant Inter-SC Trade Period. Physical Trades that are individually valid are concatenated (daisy chained) with other supporting Physical Trades at the same PNode or Aggregated Pricing Node of the Generating Unit or Physical Scheduling Plant. Once that concatenation is complete, the CAISO will determine whether the concatenated Physical Trades are physically supported by either another Inter-SC Trade of Energy at that same location or the Bid submitted in the relevant CAISO Market on behalf of the resource for that Physical Trade, individually and in the aggregate. If a Physical Trade is not adequately physically supported, the quantities in the Physical Trades of that Scheduling Coordinator and its downstream trading counter-parties are reduced on a pro-rata basis until those Physical Trades are valid. In performing physical pre-market validation of Inter-SC Trades of Energy in ~~HASP~~the RTM, the CAISO also considers final Inter-SC Trades of Energy for the DAM in determining whether the ~~HASP~~RTM Physical Trades are physically supported individually or in the aggregate. Specifically, the CAISO determines whether the resource's ~~submitted~~ Bid in ~~HASP~~the RTM is greater than or equal to the sum of: (1) final Day-Ahead Inter-SC Trades of Energy at that location, (2) the additional Inter-SC Trades of Energy for the ~~HASP~~RTM at that location and (3) the sum of all upward Day-Ahead Ancillary Services Awards at that location. If the amounts are greater than the resource's submitted Bids in ~~HASP~~the RTM, the CAISO will adjust down on a prorated basis the ~~HASP~~RTM Physical Trades. Final Day-Ahead Physical Trades are not adjusted in the ~~HASP~~RTM pre-market validation. The CAISO does not perform any Settlement on Physical Trade quantities (MWh) that are curtailed during Physical Trade pre-market validation.

28.1.6.3 Physical Trade Post-Market Confirmation

The CAISO conducts post-market confirmation of Physical Trades that pass pre-market validation in Section 28.1.6.2 after the Market Clearing and the market results are posted to ensure that the Generating Unit or Physical Scheduling Plant has a Schedule that can support all of the Physical Trades. During the post-market confirmation process, the MWh quantity of Physical Trades that passed the CAISO's pre-market validation process may be reduced if the resource supporting the Physical Trades has a Day-Ahead Schedule, HASP Block Intertie Schedule, or HASP Advisory Schedule that is, on average, below the quantity of Physical Trades at that Location. The MWh quantities of Physical Trades that are reduced during the post-market confirmation process are settled at the Existing Zone Generation Trading Hub price for the Existing Zone associated with the resource identified in the Inter-SC Trade of Energy. The portion of Physical Trades that remains intact will be settled at the relevant LMP for the identified PNode for the Generating Unit or Aggregated Pricing Node for the Physical Scheduling Plant.

* * *

28.2.2 Validation

The CAISO's validation of Inter-SC Trades of AS will begin upon submission of an Inter-SC Trade of AS. The CAISO shall conduct a final validation for Inter-SC Trades of AS at the end of the ~~HASP~~RTM Inter-SC Trade Period. The CAISO will validate each submitted Inter-SC Trade of AS to verify that the contents of the submission match the submittal by the counter-party Scheduling Coordinator by type (Regulation Up, Regulation Down, Spinning Reserve and Non-Spinning Reserve), quantity (MW), and time period. The CAISO will inform the submitting Scheduling Coordinators regarding the validity of a submitted trade of an AS and will allow the Scheduling Coordinator to resubmit the entire Inter-SC Trade of AS if it is not accepted. If only one of the two Scheduling Coordinators successfully submits an Inter-SC Trade of AS, the CAISO will notify both Scheduling Coordinators that the Inter-SC Trade of AS for the specific hour does not match the corresponding Inter-SC Trade of AS. If both Scheduling Coordinators successfully submit the Inter-SC Trade of AS, the CAISO will notify the Scheduling Coordinators that their Inter-SC Trade of AS for the specific hour has been accepted. An Inter-SC Trade of Ancillary Services submitted at a later time, but before the deadline for the submission of the trade for the Trading Hour,

renders a previously submitted Inter-SC Trade of AS invalid if it applies to the same hour, same type of AS, and the same Scheduling Coordinators to whom and from whom the AS is traded.

28.2.3 Submission Of Inter-SC Trades Of Ancillary Services

Scheduling Coordinators may submit Inter-SC Trades of Ancillary Services at any time during the ~~HASP~~RTM Inter-SC Trade Period.

* * *

28.3.2 Validation

The CAISO's validation of Inter-SC Trades of IFM Load Uplift Obligations will begin upon submission of an Inter-SC Trade of IFM Load Uplift Obligation. The CAISO shall conduct a final validation for Inter-SC Trades of IFM Load Uplift Obligations at the end of the ~~HASP~~RTM Inter-SC Trade Period. The CAISO will validate each submitted Inter-SC Trade of IFM Load Uplift Obligation to verify that the contents of the submission match the submittal by the counter-party Scheduling Coordinator in terms of quantity (MW), and time period. The CAISO will inform the submitting Scheduling Coordinators regarding the validity of a submitted Inter-SC Trade of IFM Load Uplift Obligation and will allow the Scheduling Coordinator to resubmit the entire Inter-SC Trade of IFM Load Uplift Obligation if it is not accepted. If only one of the two Scheduling Coordinators successfully submits an Inter-SC Trade of IFM Load Uplift Obligation, the CAISO will notify both Scheduling Coordinators that the Inter-SC Trade of IFM Load Uplift Obligation for the specific hour does not match the corresponding Inter-SC Trade of IFM Load Uplift Obligation. If both Scheduling Coordinators successfully submit the Inter-SC Trade of IFM Load Uplift Obligation, the CAISO will notify the Scheduling Coordinators that their Inter-SC Trade of IFM Load Uplift Obligations for the specific hour has been accepted. The CAISO will verify that an Inter-SC Trade of IFM Load Uplift Obligation is between different Scheduling Coordinators that are authorized to participate in the CAISO Markets during the time period covered by the trade and that the Trading Hour and the quantity of the trade must be greater than or equal to zero. An Inter-SC Trade of IFM Load Uplift Obligation submitted at a later time renders a previously submitted Inter-SC Trade of IFM Load Uplift Obligation invalid if it applies to the same hour and

the same Scheduling Coordinators to whom and from whom the net IFM Load Uplift Obligation is traded.

28.3.3 Submission Of Inter-SC Trades Of IFM Load Uplift Obligation

Scheduling Coordinators may submit Inter-SC Trades of IFM Load Uplift Obligations at any time during the ~~HASP~~RTM Inter-SC Trade Period.

* * *

30.1.2 ~~HASP And~~ Real-Time Market

Economic Bids and Self-Schedules submitted in the ~~HASP~~RTM apply to a single Trading Hour and are used ~~in the HASP and~~ for all market processes of the RTM. The CAISO will require Scheduling Coordinators to honor their Day-Ahead Ancillary Services Awards when submitting Ancillary Services Bids in the ~~HASP~~RTM. Bids for Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve service for each Settlement Period must be received at least seventy-five minutes prior to the commencement of that Settlement Period. The Bids shall include information for only the relevant Settlement Period. Failure to provide the information within the stated ~~time frame~~timeframe shall result in the Bids being declared invalid and rejected by the CAISO.

30.2 Bid Types

There are three types of Bids: Energy Bids (which include Virtual Bids), Ancillary Services Bids, and RUC Availability Bids. Each Bid type can be submitted as either an Economic Bid or a Self-Schedule (except for RUC Availability Bids and Virtual Bids, which cannot be self-scheduled). Economic Bids specify prices for MW amounts of capacity or MWh amounts of Energy. Self-Schedules do not have any prices associated for MW or MWh. Energy Bids, including both Economic Bids and Self-Schedules~~,~~ (where Self-Schedules are otherwise permitted), may be either Supply Bids, ~~-~~Demand Bids, Virtual Supply Bids, or Virtual Demand Bids. Ancillary Services Bids and RUC Availability Bids are Supply Bids only. Ancillary Services may be self-provided by providing a Submission to Self-Provide an Ancillary Service and having that submission accepted by the CAISO. Rules for submitting the three types of Bids vary by the type

of resource to which the Bid applies as described in Section 30.5 and as further required in each CAISO Markets process as specified in Sections 31, 33, and 34.

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30.5.1 General Bidding Rules

(a) All Energy and Ancillary Services Bids of each Scheduling Coordinator submitted to the DAM for the following Trading Day shall be submitted at or prior to 10:00 a.m. on the day preceding the Trading Day, but no sooner than seven (7) days prior to the Trading Day. All Energy and Ancillary Services Bids of each Scheduling Coordinator submitted to the ~~HASP~~RTM for the following Trading Day shall be submitted starting from the time of publication, at 1:00 p.m. on the day preceding the Trading Day, of DAM results for the Trading Day, and ending seventy-five (75) minutes prior to each applicable Trading Hour in the RTM. Scheduling Coordinators may submit only one set of Bids to the RTM for a given Trading Hour, which the CAISO uses for all Real-Time Market processes. The CAISO will not accept any Energy or Ancillary Services Bids for the following Trading Day between 10:00 a.m. on the day preceding the Trading Day and the publication, at 1:00 p.m. on the day preceding the Trading Day, of DAM results for the Trading Day;

(b) Bid prices submitted by a Scheduling Coordinator for Energy accepted and cleared in the IFM and scheduled in the Day-Ahead Schedule may be increased or decreased in the ~~HASP~~RTM . Bid prices for Energy submitted but not scheduled in the Day-Ahead Schedule may be increased or decreased in the ~~HASP~~RTM. Incremental Bid prices for Energy associated with Day-Ahead AS or RUC Awards in Bids submitted to the ~~HASP~~RTM may be revised. Scheduling Coordinators may revise ETC Self-Schedules for Supply ~~only~~ in the ~~HASP~~RTM to the extent such

a change is consistent with TRTC Instructions provided to the CAISO by the Participating TO in accordance with Section 16. Scheduling Coordinators may revise TOR Self-Schedules for Supply only in the HASP to the extent such a change is consistent with TRTC Instructions provided to the CAISO by the Non-Participating TO in accordance with Section 17. Energy associated with awarded Ancillary Services capacity cannot be offered in the ~~HASP or~~ Real-Time Market separate and apart from the awarded Ancillary Services capacity;

(c) Scheduling Coordinators may submit Energy, AS and RUC Bids in the DAM that are different for each Trading Hour of the Trading Day;

(d) Bids for Energy or capacity that are submitted to one CAISO Market, but are not accepted in that market are no longer a binding commitment and Scheduling Coordinators may submit Bids in a subsequent CAISO Market at a different price;

(e) The CAISO shall be entitled to take all reasonable measures to verify that Scheduling Coordinators meet the technical and financial criteria set forth in Section 4.5.1 and the accuracy of information submitted to the CAISO pursuant to this Section 30; and

(f) In order to retain the priorities specified in Section 31.4 and 34.~~10~~12 for scheduled amounts in the Day-Ahead Schedule associated with ETC and TOR Self-Schedules or Self-Schedules associated with Regulatory Must-Take Generation, a Scheduling Coordinator must submit to the ~~HASP and~~ Real-Time Market ETC or TOR Self-Schedules, or Self-Schedules associated with Regulatory Must-Take Generation, at or below the Day-Ahead Schedule quantities associated with the scheduled ETC, TOR or Regulatory Must-Take Generation Self-Schedules. If the Scheduling Coordinator fails to submit such ~~HASP or~~ Real-Time Market ETC, TOR or Regulatory Must-Take Generation Self-Schedules, the

defined scheduling priorities of the ETC, TOR, or Regulatory Must-Take Generation Day-Ahead Schedule quantities may be subject to adjustment in the HASP and the Real-Time Market as further provided in Section 31.4 and 34.~~10~~12 in order to meet operating conditions.

(g) For Multi-Stage Generating Resources that receive a Day-Ahead Schedule, are awarded a RUC Schedule, or receive an Ancillary Services Award the Scheduling Coordinator must submit an Energy Bid in the Real-Time Market for the same Trading Hour(s~~)~~). If the Scheduling Coordinator submits an Economic Bid for such Trading Hour(s), the Economic Bid must be for either: the same MSG Configuration scheduled or awarded in the Integrated Forward Market, or the MSG Configuration committed in RUC. If the Scheduling Coordinator submits a Self-Schedule in the Real-Time Market for such Trading Hour(s), then the Energy Self-Schedule may be submitted in any registered MSG Configuration, including the MSG Configuration awarded in the Day-Ahead Market, that can support the awarded Ancillary Services (as further required by Section 8). Scheduling Coordinators for Multi-Stage Generating Resources may submit into the Real-Time Market bids from up to six (6) MSG Configurations in addition to the MSG Configuration scheduled or awarded in the Integrated Forward Market and Residual Unit Commitment, provided that the MSG Transitions between the MSG Configurations bid into the Real-Time Market are feasible and the transition from the previous Trading Hour are also feasible.

(h) For the Trading Hours that Multi-Stage Generating Resources do not have a CAISO Schedule or award from a prior CAISO Market run, the Scheduling Coordinator can submit up to six (6) MSG Configurations into the RTM.

(i) A Scheduling Coordinator cannot submit a Bid to the CAISO Markets for a MSG Configuration into which the Multi-Stage Generating Resource cannot transition due to lack of Bids for the specific Multi-Stage Generating Resource in other MSG Configurations that are required for the requisite MSG Transition.

(j) In order for Multi-Stage Generating Resource to meet any Resource Adequacy must-offer obligations, the responsible Scheduling Coordinator must submit either an Economic Bid or Self-Schedule for at least one MSG Configuration into the Day-Ahead Market and Real-Time Market that is capable of fulfilling that Resource Adequacy obligation, as feasible. The Economic Bid shall cover the entire capacity range between the maximum bid-in Energy MW and the higher of Self-Scheduled Energy MW and the Multi-Stage Generating Resource plant-level PMin.

(k) For any given Trading Hour, a Scheduling Coordinator may submit Self-Schedules and/or Submissions to Self-Provide Ancillary Services in only one MSG Configuration for each Generating Unit or Dynamic Resource-Specific System Resource.

(l) In any given Trading Hour in which a Scheduling Coordinator has submitted a Self-Schedule for a Multi-Stage Generating Resource, the Scheduling Coordinator may also submit Bids for other MSG Configurations provided that they concurrently submit Bids that enable the applicable CAISO Market to transition the Multi-Stage Generating Resource to other MSG Configurations.

(m) If in any given Trading Hour the Multi-Stage Generating Resource was awarded Regulation or Operating Reserves in the IFM, any Self-Schedules or Submissions to Self-Provide Ancillary Services the Scheduling Coordinator submits for that Multi-Stage Generating

Resource in the RTM must be for the same MSG Configuration for which Regulation or Operating Reserve is Awarded in IFM for that Multi-Stage Generating Resource in that given Trading Hour.

(n) If a Multi-Stage Generating Resource has received a binding RUC Start-Up Instruction as provided in Section 31, any Self-Schedule or Submission to Self-Provide Ancillary Services in the RTM must be in the same MSG Configuration committed in RUC.

(o) If in any given Trading Hour the Multi-Stage Generating Resource is scheduled for Energy in the IFM, any Self-Schedules the Scheduling Coordinator submits for that Multi-Stage Generating Resource in the RTM must be for the same MSG Configuration for which Energy is scheduled in IFM for that Multi-Stage Generating Resource in that given Trading Hour.

(p) For a Multi-Stage Generating Resource, the Bid(s) submitted for the resource's configuration(s) shall collectively cover the entire capacity range between the maximum bid-in Energy MW and the higher of the Self-Scheduled Energy MW and the Multi-Stage Generating Resource plant-level PMin. This rule shall apply separately to the Day-Ahead Market and the Real-Time Market.

(q) A Scheduling Coordinator may submit a Self-Schedule Hourly Block for the RTM as an import to or an export from the CAISO Balancing Authority Area and may also submit Self-Scheduled Hourly Blocks for Ancillary Services imports. Such a Bid shall be for the same MWh quantity for each of the four fifteen (15)-minute intervals that make up the applicable Trading Hour.

(r) A Scheduling Coordinator may submit a Variable Energy Resource Self-Schedule for the RTM can be submitted from a Variable Energy Resource. A Scheduling Coordinator can use either the CAISO forecast

for Expected Energy in the RTM or can provide its own forecast for Expected Energy pursuant to the requirements specified in Section 4.8.2. The Scheduling Coordinator must indicate in the Master File whether it is using its own forecast or the CAISO forecast for its resource in support of the Variable Energy Self-Schedule. The Scheduling Coordinator is not required to include the same MWh quantity for each of the four fifteen (15)-minute intervals that make up the applicable Trading Hour for the Variable Energy Resource Self-Schedule include. If an external Variable Energy Resource that is not using a forecast of its output provided by the CAISO submits a Variable Energy Resource Self-Schedule and the Expected Energy is not delivered in the FMM, the Scheduling Coordinator for the Variable Energy Resource will be subject to the Decline Potential Charge as described in Section 11.31. Scheduling Coordinators for Dynamically Scheduled Variable Energy Resources that provide the CAISO with a two-hour rolling forecast with five-minute granularity can submit Variable Energy Resource Self-Schedules.

(s) Scheduling Coordinators can submit Economic Hourly Block Bids to be considered in the HASP and to be accepted as binding Schedules with the same MWh award for each of the four FMM intervals. Scheduling Coordinator can also submit Economic Hourly Block Bids for Ancillary Services. As specified in Section 11, a cleared Economic Hourly Block Bid is not eligible for Bid Cost Recovery.

(t) Scheduling Coordinators can submit Economic Hourly Block Bids with Intra-Hour Option. If accepted in the HASP, such a Bid creates a bindingschedule with same MWh awards for each of the four FMM intervals. After that, the RTM can optimize such schedules for economic reasons once through an FMM during the Trading Hour. As specified in

Section 11, a cleared Economic Hourly Block Bid with Intra-Hour Option is not eligible for Bid Cost Recovery.

(u) A Scheduling Coordinator submitting Bids to the RTM is not required to submit a Self-Schedule Hourly Block, a Variable Energy Resource Self-Schedule, an Economic Hourly Block Bid, or an Economic Hourly Block Bid with Intra-Hour Option, and may instead choose to participate in the RTM through Economic Bids or Self-Schedules.

30.5.2 Supply Bids

30.5.2.1 Common Elements for Supply Bids

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

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

Scheduling Coordinators submitting Bids for Scheduling Points must adhere to the e-Tagging requirements outlined in Section 30.6.2.

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30.5.2.4 Supply Bids for System Resources

In addition to the common elements listed in Section 30.5.2.1, Supply Bids for System Resources shall also contain: the relevant Ramp Rate; Start-Up Costs; and Minimum Load Costs.

Resource-Specific System Resources may elect the Proxy Cost option or Registered Cost option for Start-Up Costs and Minimum Load Costs as provided in Section 30.4. Other System Resources are not eligible to recover Start-Up Costs and Minimum Load Costs. Resource-Specific System Resources are eligible to participate in the Day-Ahead Market on an equivalent basis as Generating Units and are not obligated to participate in RUC or the RTM if the resource did not receive a Day-Ahead Schedule unless the resource is a Resource Adequacy Resource. If the Resource-Specific System Resource is a Resource Adequacy Resource, the Scheduling Coordinator for the resource is obligated to make it available to the CAISO Market as prescribed by Section 40.6. Dynamic Resource-Specific System Resources are also eligible to participate in the HASP and RTM on an equivalent basis as Generating Units. ~~Non-Dynamic Resource-Specific System Resources will be treated like other System Resources in the HASP and RTM.~~ The quantity (in MWh) of Energy categorized as Interruptible Imports (non-firm imports) can only be submitted through Self-Schedules in the Day-Ahead Market and cannot be incrementally increased in the HASP or RTM. Bids submitted to the Day-Ahead Market for ELS Resources will be applicable for two days after they have been submitted and cannot be changed the day after they have been submitted.

* * *

30.5.2.5 Supply Bids for Metered Subsystems

Consistent with the bidding rules specified in this Section 30.5, Scheduling Coordinators that represent MSS Operators may submit Bids for Energy and Ancillary Services, including Self-Schedules and Submissions to Self-Provide an Ancillary Service, to the DAM. All Bids to supply Energy by MSS Operators must identify each Generating Unit on an individual unit basis. The CAISO will not accept aggregated Generation Bids without complying with the requirements of Section 4.9.12 of the CAISO Tariff. All Scheduling Coordinators that represent MSS Operators must submit Demand Bids at the relevant MSS LAP. Scheduling Coordinators that represent MSS Operators must comply with Section 4.9 of the CAISO Tariff. Scheduling Coordinators that represent MSS Operators that have opted out of RUC participation pursuant to Section 31.5 must Self-Schedule one hundred percent (100%) of the Demand Forecast for the MSS. For an MSS

that elects Load following, the MSS Operator shall also self-schedule or bid Supply to match the Demand Forecast. All Bids for MSSs must be identify each Generating Unit on an individual unit basis or a System Unit. For an MSS that elects Load following consistent with Section 4.9.13.2, the Scheduling Coordinator for the MSS Operator must include the following additional information with its Bids: the Generating Unit(s) that are Load following; the range of the Generating Unit(s) being reserved for Load following; whether the quantity of Load following capacity is either up or down; and, if there are multiple Generating Units in the MSS, the priority list or distribution factors among the Generating Units. The CAISO will not dispatch the resource within the range declared as Load following capacity, leaving that capacity entirely available for the MSS to dispatch. The CAISO uses this information in the IFM runs and the RUC to simulate MSS Load following. The Scheduling Coordinator for the MSS Operator may change these characteristics through the Bid submission process in the ~~HASP.~~RTM.

If the Load following resource is also an RMR Unit, the MSS Operator must not specify the Maximum Net Dependable Capacity specified in the RMR Contract as Load following up or down capacity to allow the CAISO to access such capacity for RMR Dispatch.

30.5.2.6 Ancillary Services Bids

There are four distinct Ancillary Services: Regulation Up, Regulation Down, Spinning Reserve and Non-Spinning Reserve. A resource shall be eligible to provide Ancillary Service if it has complied with the CAISO's certification and testing requirements as contained in Appendix K and the CAISO's Operating Procedures. Scheduling Coordinators may use Dynamic System Resources to Self-Provide Ancillary Services as specified in Section 8. ~~Scheduling Coordinators may not use Non-Dynamic System Resources to Self-Provide Ancillary Services.~~ All System Resources, including Dynamic System Resources and Non-Dynamic System Resources, will be charged the Shadow Price as prescribed in Section 11.10, for any awarded Ancillary Services. A Scheduling Coordinator may submit Ancillary Services Bids for Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve for the same capacity by providing a separate price in $/MW per hour as desired for each Ancillary Service. The Bid for each Ancillary Services is a single Bid segment. Only resources certified by the CAISO as capable of providing Ancillary

Services are eligible to provide Ancillary Services and submit Ancillary Services Bids. In addition to the common elements listed in Section 30.5.2.1, all Ancillary Services Bid components of a Supply Bid must contain the following: (1) the type of Ancillary Service for which a Bid is being submitted; (2) Ramp Rate (Operating Reserve Ramp Rate and Regulation Ramp Rate, if applicable); and (3) Distribution Curve for Physical Scheduling Plant or System Unit. A Scheduling Coordinator may only submit an Ancillary Services Bid or Submission to Self-Provide an Ancillary Service for Multi-Stage Generating Resources for the Ancillary Service for which the specific MSG Configurations are certified. For any such certified MSG Configurations the Scheduling Coordinator may submit only one Operating Reserve Ramp Rate and Regulation Ramp Rate. An Ancillary Services Bid submitted to the Day-Ahead Market when submitted to the Day-Ahead Market may be, but is not required to be, accompanied by an Energy Bid that covers the capacity offered for the Ancillary Service. Submissions to Self-Provide an Ancillary Services submitted to the Day-Ahead Market when submitted to the Day-Ahead Market may be, but are not required to be, accompanied by an Energy Bid that covers the capacity to be self-provided. If a Scheduling Coordinator's Submission to Self-Provide an Ancillary Service is qualified as specified in Section 8.6, the Scheduling Coordinator must submit an Energy Bid that covers the self-provided capacity prior to the close of the Real-Time Market for the day immediately following the Day-Ahead Market in which the Ancillary Service Bid was submitted. Except as provided below, the Self-Schedule for Energy need not include a Self-Schedule for Energy from the resource that will be self-providing the Ancillary Service. If a Scheduling Coordinator is self-providing an Ancillary Service from a Fast Start Unit, no Self-Schedule for Energy for that resource is required. If a Scheduling Coordinator proposes to self-provide Spinning Reserve, the Scheduling Coordinator is obligated to submit a Self-Schedule for Energy for that particular resource, unless as discussed above the particular resource is a Fast Start Unit. When submitting Ancillary Service Bids in the ~~HASP and~~ Real-Time Market, Scheduling Coordinators for resources that either have been awarded or self-provide Spinning Reserve or Non-Spinning Reserve capacity in the Day-Ahead Market must submit an Energy Bid for at least the awarded or

self-provided Spinning Reserve or Non-Spinning Reserve capacity, otherwise the CAISO will apply the Bid validation rules described in Section 30.7.6.1.

As provided in Section 30.5.2.6.4, a Submission to Self-Provide an Ancillary Service shall contain all of the requirements of a Bid for Ancillary Services with the exception of Ancillary Service Bid price information. In addition, Scheduling Coordinators must comply with the Ancillary Services requirements of Section 8. Scheduling Coordinators submitting Self-Schedule Hourly Blocks for Ancillary Services Bids for ~~System Resources in~~ the ~~HASP or~~ Real-Time Market must also submit an Energy Bid for the associated Ancillary Services Bid under the same Resource ID, otherwise the bid validation rules in Section 30.7.6.1 will apply to cover any portion of the Ancillary Services Bid not accompanied by an Energy Bid. As described in Section ~~33.7~~34.2.3, if the resource ~~is~~submits a ~~Non-Dynamic System Resource~~Self-Scheduled Hourly Block, the CAISO will only use the Ancillary Services Bid in the ~~HASP~~RTM optimization and will not use the associated Energy Bid for the same Resource ID to schedule Energy from the Non-Dynamic System Resource in the ~~HASP~~RTM. Scheduling Coordinators must also comply with the bidding rules associated with the must offer requirements for Ancillary Services specified in Section 40.6.

* * *

30.5.4 Wheeling Through Transactions

A Wheeling Through transaction consists of an Export Bid and an Import Bid with the same Wheeling reference (a unique identifier for each Wheeling Through transaction). ~~-~~If the Wheeling reference does not match at the time the relevant market closes, the Wheeling Through transaction will be erased; this includes any ~~Energy~~Economic Bid or Self-Schedule for the resource for that Trading Hour.~~-~~ Wheeling Through transactions with matching Wheeling references will be kept balanced in the IFM and ~~in the HASP and~~ RTM; that is, to the extent an Export Bid or Import Economic Bid or Self-Schedule specify different quantities, only that matching quantity will clear the CAISO Markets.

* * *

30.6.2 ~~[NOT USED]~~E-Tag Rules and Treatment of Intertie Schedules

In addition to complying with all generally applicable E-Tagging requirements, Scheduling Coordinators must submit their E-tags consistent with the requirements specified in this Section 30.6.2. If a Scheduling Coordinator receives an intra-hour Schedule change, then the Scheduling Coordinator must, by twenty minutes before the start of the FMM interval to which the Schedule change applies, ensure that an updated energy profile reflects the change. Absent extenuating circumstances, the CAISO automatically updates Energy profiles on E-tags for Energy Schedules that change from HASP to the FMM within a Trading Hour. In performing this service for a Scheduling Coordinator, the CAISO does not assume any responsibility for compliance with any E-tag requirements or obligations to which the Scheduling Coordinator is subject. The changed energy profile will apply for the balance of the operating hour unless it is subsequently changed by a further updated energy profile.

30.6.2.1 Self-Scheduled Hourly Blocks

By twenty minutes prior to the applicable Trading Hour, the Scheduling Coordinator must submit an E-Tag in support of Self-Scheduled Hourly Blocks. The transmission profile must be greater than or equal to the Energy profile, and the Energy profile must equal the Self-Scheduled Hourly Block. The CAISO may modify the Energy profile due to Reliability related curtailments.

30.6.2.2 Variable Energy Resource Self-Schedule

By twenty minutes prior to the applicable Trading Hour, the Scheduling Coordinator must submit an E-Tag in support of a Variable Energy Resource Self-Schedule. The transmission profile must be greater than or equal to the Energy profile, and the Energy profile must equal the Variable Energy Resource Self-Schedule. The CAISO may modify the Energy profile due to Reliability related curtailments.

30.6.2.3 Economic Hourly Block Bid

By twenty minutes prior to the applicable Trading Hour, the Scheduling Coordinator must submit an E-Tag in support of an Economic Hourly Block Bid. The transmission profile must be greater than or equal to the Energy profile, and the Energy profile must equal the Economic Hourly Block Bid as awarded through HASP. The CAISO may modify the Energy profile due to Reliability related curtailments.

30.6.2.4 Economic Hourly Block Bid with Intra-Hour Option

By twenty minutes prior to the applicable Trading Hour, the Scheduling Coordinator must submit an E-Tag in support of an Economic Hourly Block Bid. The transmission profile must be greater than or equal to the Energy profile, and the Energy profile must equal the Economic Hourly Block Bid as awarded through HASP. The CAISO may modify the Energy profile due to Reliability related curtailments. In the case of an intra-hour redispatch from the FMM, the CAISO may increment or decrement the Energy profile to correspond to the intra-hour redispatch.

30.6.2.5 FMM Economic Bid

By twenty minutes prior to the applicable Trading Hour, the Scheduling Coordinator must submit an E-Tag in support of a FMM Economic Bid. The transmission profile must be greater than or equal to the maximum bid-in capacity for the Trading Hour, and the Energy profile must equal the MWs awarded for the first FMM interval of the Operating Hour. If the Scheduling Coordinator intends to limit its participation in the FMM to the quantity in the HASP advisory energy schedule (including zero), the Scheduling Coordinator may update its transmission profile to the maximum amount it wants to make available to the FMM prior to the start of the binding FMM optimization, which is no earlier than thirty-seven and a half minutes before the applicable Trading Hour. If the Scheduling Coordinator does not have a transmission profile greater than or equal to its advisory Energy schedule, then the CAISO will limit the schedule for Energy in the FMM so that it does not exceed amounts greater than what is listed in the transmission profile. Cleared FMM Economic Bids are eligible for Bid Cost Recovery as specified in Section 11.8.

* * *

30.7.1 Scheduling Coordinator Access

Each Scheduling Coordinator will be provided access to the CAISO's secure communication system to submit, modify and cancel Bids prior to the close of both the DAM and ~~HASP~~RTM, as specified in Section 30.5.1.~~-~~ The CAISO shall provide information regarding submitted Bids including, but not be limited to, the following: (i) notification of acceptance; (ii) notification of validation; (iii) notification of rejection; (iv) notification of

status; (v) notification of submission error(s); and (vi) default modification or generation of Bids as further provided below, if any, on behalf of Scheduling Coordinators.

* * *

30.7.3.6.3 Position Limits

For each Convergence Bidding Entity, the CAISO will reject all Virtual Bids submitted by its Scheduling Coordinator at any Eligible PNode ~~or~~, Eligible Aggregated PNode (other than a Default LAP or Trading Hub), or Intertie that exceed the position limits specified in this Section 30.7.3.6.3. If the Scheduling Coordinator uses multiple SCIDs on behalf of a Convergence Bidding Entity, the position limits will apply to the sum of those Virtual Bids submitted at the Eligible PNode ~~or~~, Eligible Aggregated PNode (other than a Default LAP or Trading Hub~~).~~), or Intertie. The CAISO will perform all position limit calculations based on the highest Virtual Bid segment MW point submitted in the Virtual Bid Curve. The CAISO will not net Virtual Supply Bids and Virtual Demand Bids in performing the position limit calculations. The affected Scheduling Coordinator will be provided notice that position limits have been violated. If the Scheduling Coordinator does not resubmit Virtual Bids within the position limits, the CAISO will reject Virtual Bids for all hours at each Eligible PNode ~~or~~, Eligible Aggregated PNode (other than a Default LAP or Trading Hub~~)~~), and Intertie where the position limits are violated. Position limits only apply to Eligible PNodes or Eligible Aggregated PNodes (other than Default LAPs or Trading Hubs~~).~~), and Interties.

* * *

30.7.3.6.3.2 Position Limits at Interties

For an Intertie, the locational limits will be equal to a percentage of the Operating Transfer Capability of the Intertie. The percentages used to calculate the position limits of each Convergence Bidding Entity at Interties will be the following percentages of the published locational limits:

(a) Position limits of zero (0) percent will apply during the time period beginning as of the effective date of this tariff provision through the last day of the twelfth month following the effective date of this section 30.7.3.6.3.2.

(b) Position limits of five (5) percent will apply during the time period beginning as of the first day of the thirteenth month following the effective date of this tariff provision through the last day of the twentieth month following the effective date of this tariff provision.

(c) Position limits of twenty-five (25) percent will apply during the time period beginning on the first day of the twenty-first month following the effective date of this tariff provision through the last day of the twenty-fourth month following the effective date of this tariff provision.

(d) Position limits of fifty (50) percent will apply during the time period beginning on the first day of the twenty-fifth month following the effective date of this tariff provision through the last day of the twenty-eighth month following the effective date of this tariff provision.

(e) Position limits will cease to apply beginning on the first day of the twenty-ninth month following the effective date of this tariff provision.

The CAISO will enforce the locational limits for Interties at Bid submission and at Market Close for Virtual Bids. The CAISO will utilize the 9:00 AM Operating Transfer Capability for Bids submitted after 9:00 AM until the close of the Day-Ahead Market for the next Trading Day.

* * *

30.7.4 ~~HASP And~~ RTM Validation

~~The HASP and~~ RTM Bids will include the same validation process implemented in the DAM except that the CAISO will not validate the Bid before and again after the Master File Data update. ~~HASP and~~ RTM Bids are only validated based on the current Master File Data on the relevant Trading Day.

* * *

30.7.6 Validation And Treatment Of Ancillary Services Bids

30.7.6.1 Validation of Ancillary Services Bids

Throughout the validation process described in Section 30.7, the CAISO will verify that each Ancillary Services Bid conforms to the content, format and syntax specified for the relevant

Ancillary Service. If the Ancillary Services Bid does not so conform, the CAISO will send a notification to the Scheduling Coordinator notifying the Scheduling Coordinator of the errors in the Bids as described in Section 30.7. When the Bids are submitted, a technical validation will be performed to verify that the bid quantity of Regulation, Spinning Reserve, or Non-Spinning Reserve does not exceed the certified Ancillary Services capacity for Regulation, or Operating Reserves on the Generating Units, System Units, Participating Loads, Proxy Demand Resources, and external imports/exports bid. The Scheduling Coordinator will be notified within a reasonable time of any validation errors. For each error detected, an error message will be generated by the CAISO in the Scheduling Coordinator's notification screen, which will specify the nature of the error. The Scheduling Coordinator can then look at the notification messages to review the detailed list of errors, make changes, and resubmit if it is still within the CAISO's timing requirements. The Scheduling Coordinator is also notified of successful validation. If a resource is awarded or has qualified Self-Provided Ancillary Services in the Day-Ahead Market, the following rules will apply: (1): if no Energy Self-Schedule is submitted to support a Submission to Self-Provide an Ancillary Service for Regulation, the Submission to Self-Provide an Ancillary Service will be invalidated: (2) if no Energy Supply Bid is submitted to cover the awarded or Self-Provided Ancillary Services for Spinning Reserve or Non-Spinning Reserve by the Market Close of ~~HASP and~~ the RTM, the CAISO will generate or extend an Energy Supply Bid as necessary to cover the awarded or Self-Provided Ancillary Services capacity using the registered values in the Master File and relevant fuel prices as described in the Business Practice Manuals for use in the ~~HASP~~RTM and IFM. If an AS Bid or Submission to Self-Provide an AS is submitted in the Real-Time Market for Spinning Reserve or Non-Spinning Reserve without an accompanying Energy Supply Bid at all, the AS Bid or Submission to Self-Provide an Ancillary Service will be erased. If an AS Bid is submitted in the ~~HASP or~~ Real-Time Market for Spinning Reserve and Non-Spinning Reserve with only a partial Energy Supply Bid for the AS capacity, the CAISO will generate an Energy Supply Bid for the uncovered portions. If a Submission to Self-Provide an Ancillary Service is submitted in the ~~HASP or~~ Real-Time Market for Spinning Reserve and Non-Spinning Reserve with only a partial Energy Supply Bid for the AS capacity bid

in, the CAISO will not generate or extend an Energy Supply Bid for the uncovered portions. For Generating Units with certified Regulation capacity, if there no Bid for Regulation in the Real-Time Market, but there is a Day-Ahead award for Regulation Up or Regulation Down or a submission to self-provide Regulation Up or Regulation Down, respectively, the CAISO will generate a Regulation Up or Regulation Down Bid at the default Ancillary Service Bid price of $0 up to the certified Regulation capacity for the Generating Unit minus any Regulation awarded or self-provided in the Day-Ahead. If there is a Bid for Regulation Up or Regulation Down in the Real-Time Market, the CAISO will increase the respective Bid up to the certified Regulation capacity for the Generating Unit minus any Regulation awarded or self-provided in the Day-Ahead. If a Self-Schedule amount is greater than the Regulation Limit for Regulation Up, the Regulation Up Bid will be erased.

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

30.7.6.2 Treatment of Ancillary Services Bids

When Scheduling Coordinators bid into the Regulation Up, Regulation Down, Spinning Reserve, and Non-Spinning Reserve markets, they may submit Bids for the same capacity into as many of these markets as desired at the same time by providing the appropriate Bid information to the CAISO. The CAISO optimization will evaluate AS Bids simultaneously with Energy Bids. A Scheduling Coordinator may specify that its Bid applies only in the markets it desires. A Scheduling Coordinator shall also have the ability to specify different capacity prices for the Spinning Reserve, Non-Spinning Reserve, and Regulation markets. A Scheduling Coordinator providing one or more Regulation Up, Regulation Down, Spinning Reserve or Non-Spinning Reserve services may not change the identification of the Generating Units or Proxy Demand Resources offered in the Day-Ahead Market or in the Real-Time Market

for such services unless specifically approved by the CAISO (except with respect to System Units, if any, in which case Scheduling Coordinators are required to identify and disclose the resource specific information for all Generating Units, Participating Loads, and Proxy Demand Resources constituting the System Unit for which Bids and Submissions to Self-Provide Ancillary Services are submitted into the CAISO's Day-Ahead Market and Real-Time Market). The following principles will apply in the treatment of Ancillary Services Bids in the CAISO Markets:

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

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

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

(d) evaluate Import Bids along with Bids from internal resources (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area);

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

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

* * *

30.8 Bids On Out-Of-Service Paths At Scheduling Points Prohibited

Scheduling Coordinators shall not submit any Bids, including Virtual Bids, or ETC Self-Schedules at Scheduling Points using a transmission path for any Settlement Period for which the Total Transfer Capability for that path is zero (0) MW. The CAISO shall reject Bids or ETC Self-Schedules submitted at Scheduling Points where the Total Transfer Capability on the transmission path is zero (0) MW. If the Total Transfer Capability of a transmission path at the relevant Scheduling Point is reduced to zero (0) after Day-Ahead Schedules have been issued, then, if time permits, the CAISO shall direct the responsible Scheduling Coordinators to reduce all MWh associated with the Bids on such zero-rated transmission paths to zero (0) in the ~~HASP.~~ RTM. As necessary to comply with Applicable Reliability Criteria, the CAISO shall reduce any non-zero (0) ~~HASP~~RTM Bids across zero-rated transmission paths to zero after the Market Close for the ~~HASP~~RTM.

30.9 Virtual Bids

Virtual Bids are Energy Bids that may be submitted only in the Day-Ahead Market, at Eligible PNodes, including PNodes located at an Intertie where virtual bidding is permitted, or Eligible Aggregated PNodes, including Aggregated PNodes located at an Intertie, where virtual bidding is permitted, by Scheduling Coordinators representing Convergence Bidding Entities. Virtual Bids are either Virtual Supply Bids or Virtual Demand Bids. A Virtual Bid submitted in the Day-Ahead Market and cleared in the IFM represents a commitment to liquidate a Day-Ahead award in the Real-Time Market at the price determined for the applicable Eligible PNode or Eligible Aggregated PNode as set forth in Section 11.3. For each SCID associated with a Convergence Bidding Entity, there may be only one Virtual Supply Bid and one Virtual Demand Bid per each Eligible PNode or Eligible Aggregated PNode in the Day-Ahead Market. The minimum size of a segment of a Virtual Bid is one (1) MW.

* * *

31.3.1.1 Integrated Forward Market Output

The IFM produces: (1) a set of hourly Day-Ahead Schedules, AS Awards, and AS Schedules for all participating Scheduling Coordinators that cover each Trading Hour of the next Trading Day; and (2) the hourly LMPs for Energy and the ASMPs for Ancillary Services to be used for settlement of the IFM. For a Multi-Stage Generating Resource, the IFM produces a Day-Ahead Schedule for no more than one MSG Configuration per Trading Hour. In addition, the IFM will produce the MSG Transition and the MSG Configuration indicators for the Multi-Stage Generating Resource, which would establish the expected MSG Configuration in which the Multi-Stage Generating Resource will operate. During a transition, the committed MSG Configuration is considered to be the "from" MSG Configuration. The CAISO will publish the LMPs at each PNode as calculated in the IFM. In determining Day-Ahead Schedules, AS Awards, and AS Schedules the IFM optimization will minimize total Bid Costs based on submitted and mitigated Bids while respecting the operating characteristics of resources, the operating limits of transmission facilities, and a set of scheduling priorities that are described in Section 31.4. In performing its optimization, the IFM first tries to complete its required functions utilizing Effective Economic Bids without adjusting Self-Schedules, and skips Ineffective Economic Bids and adjusts Self-Schedules only if it is not possible to balance Supply and Demand and manage Congestion in an operationally prudent manner with available Effective Economic Bids. The process and criteria by which the IFM adjusts Self-Schedules and other Non-priced Quantities are described in Sections 27.4.3, 31.3.1.3 and 31.4. The Day-Ahead Schedules are binding commitments, including the commitment to Start-Up, if necessary, to comply with the Day-Ahead Schedules. The CAISO will not issue separate Start-Up Instructions for Day-Ahead commitments. A resource's status, however, can be modified as a result of additional market processes occurring in the ~~HASP and~~ RTM.

* * *

31.5.3 RUC Procurement Target

The procurement target for RUC in any given Trading Hour will be determined based on the next day's hourly CAISO Forecast ~~of~~Of CAISO Demand less the Energy scheduled in the Day-Ahead Schedule, and accounting for other factors, as appropriate, such as Demand Forecast error and

estimated incremental ~~HASP~~RTM Bids including those from Participating Intermittent Resources. The adjustments listed in Sections 31.5.3.1 to 31.5.3.6 will be made to the CAISO Forecast ~~of~~Of CAISO Demand to account for the conditions as provided therein.~~-~~ Adjustments may be made on a RUC Zone basis to ensure that RUC results in adequate local capacity procurement. ~~-~~The RUC procurement target-setting procedure is designed to meet the requirements of reliable grid operation without unnecessary over-procurement of RUC Capacity or over-commitment of resources. ~~-~~Additional detail on the process for setting the RUC procurement target is specified in the Business Practice Manuals.

* * *

31.5.3.5 Real-Time Expected Incremental Supply Self-Schedule Adjustment

In order to avoid over procurement of RUC, the CAISO shall, using a similar-day approach, estimate the ~~HASP~~RTM Self-Schedules for resources that usually submit ~~HASP~~RTM Self-Schedules that are greater than their Day-Ahead Schedules. The CAISO Operator may set the length of the Self-Schedule moving average window. Initially this moving average window shall be set by default to seven (7) days; in which case the weekday estimate is based on the average of five (5) most recent weekdays and the weekend estimate is based on the average of the two (2) most recent weekend days. To the extent weather conditions differ significantly from the historical days, additional adjustment may be necessary. After determining the estimate of Real-Time Self-Schedules, using a similar day forecasting approach, the CAISO adjusts the CAISO Forecast ~~of~~Of CAISO Demand of a RUC Zone based on the forecasted quantity changes in Supply as a result of Self-Schedules submitted in the RTM. This adjustment for forecasted Real-Time Self- Schedules may result in positive or negative adjustments. Demand adjustments to the CAISO Forecast ~~of~~Of CAISO Demand result when there is a net forecast decrease in Real-Time Self-Schedule Supply relative to the Day-Ahead Schedule Supply. Supply adjustments to the individual resources occur when there is a net forecast increase in Real-Time Self-Schedule Supply relative to the Day-Ahead Schedule Supply of the individual resource.

* * *

31.6.3 Conditions Permitting CAISO To Abort Day-Ahead Market

If, despite the variation of any time requirement or the omission of any step, the CAISO either fails to receive sufficient Bids or fails to clear the Day-Ahead Market, the CAISO may abort the Day-Ahead Market and require all Bids to be submitted in the ~~HASP and~~ RTM

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31.8 Constraints Enforced at Intertie Scheduling Points

Within the IFM optimization, the CAISO enforces a constraint at each Intertie Scheduling Point such that Physical and virtual imports net of physical and virtual exports must be less than or equal to the scheduling limit at the Scheduling Point in the applicable direction. The CAISO incorporates the Shadow Price of this IFM constraint into the CAISO Market runs used to establish LMPs for both physical and virtual awards. Within the RUC process, the CAISO enforces a constraint at each Intertie Scheduling Point such that physical imports net of physical exports must be less than or equal to the scheduling limit at the Scheduling Point in the applicable direction. Through this RUC constraint the CAISO determines what Day-Ahead Schedules can have an E-Tag submitted Day-Ahead. Day-Ahead Schedules precluded from submitting an E-Tag in the Day-Ahead on this basis are exempt from the charges described in Section 11.32.

* * *

33 [Not Used]

33.1 [Not Used]

33.2 [Not Used].

33.3 [Not Used]

33.4 [Not Used]

33.5 [NOT USED]

33.6 [Not Used]

33.7 [Not Used]

33.8 [Not Used]

33.9 [Not Used]

* * *

34. Real-Time Market

The CAISO conducts the Real-Time Market on any given Operating Day in which Scheduling Coordinators may submit Bids, and the CAISO commits and Dispatches Energy and procures Energy and Ancillary Services. The Real-Time Market consists of the following processes: (1) the Hour-Ahead Scheduling Process ~~(HASP) The HASP is the hour-ahead process during the Real-Time which consists of the following activities. The HASP includes a special hourly run of the~~, (2) **Real-Time Unit Commitment (RTUC),** ~~which is also one of the component processes of the RTM. The RTUC utilizes a SCUC optimization and runs every fifteen (15) minutes, as fully described in Section 34. This Section 33 describes the special features of the specific hourly HASP run of the RTUC. The HASP combines provisions for the CAISO to issue hourly pre-dispatch instructions to System Resources that submit Energy Bids to the RTM and for the procurement of Ancillary Services on an hourly basis from System Resources, with provisions for Scheduling Coordinators to self-schedule changes to their Day-Ahead Schedules as provided in Section 33.1, and submit Bids to export Energy at Scheduling Points. The HASP also performs the MPM procedure with respect to the Bids that will be used in the HASP optimization and in the RTM processes for the same Trading Hour.~~

~~**33.1 Submission Of Bids For The HASP And RTM**~~

~~Scheduling Coordinators may submit Bids, including Self-Schedules, for Supply that will be used for the HASP and the RTM processes starting from the time Day-Ahead Schedules have been posted until seventy-five (75) minutes prior to each applicable Trading Hour in the Real-Time. This includes Self-Schedules by Participating Load that is modeled using the Pumped-Storage Hydro Unit. Scheduling Coordinators may not submit Bids, including Self-Schedules, for CAISO Demand in the HASP and RTM. Scheduling Coordinators may submit Bids, including Self-Schedules, for exports at Scheduling Points in the HASP and RTM. The rules for submitted Bids specified in Section 30 apply to Bids submitted to the HASP and RTM. After the Market Close of the HASP and the RTM the CAISO performs a validation process consistent with the provisions set forth in Section 30.7 and the following additional rules. The CAISO will generate a Self-~~

~~Schedule to cover any RUC Award or Day-Ahead Schedule in the absence of any Self-Schedule or Economic Bid components, or to fill in any gaps between any Self-Schedule Bid and any Economic Bid components to cover a RUC Award or Day-Ahead Schedule. Bids submitted to the HASP and the RTM to supply Energy and Ancillary Services will be considered in the various HASP and RTM processes, including the MPM process, the HASP optimization, the STUC, the RTUC and the RTD.~~

~~33.2 The HASP Optimization~~

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

~~33.3 Treatment Of Self-Schedules In HASP~~

~~The HASP optimization clears Bids, including Self-Schedules, while preserving all priorities in this process consistent with Section 34.10. The HASP optimization does not adjust submitted Self-Schedules unless it is not possible to balance Supply and the CAISO Forecast of CAISO Demand plus Export Bids and manage Congestion using the available Economic Bids, in which case the~~

HASP performs non-economic adjustments to Self-Schedules. The MWh quantities of Self-Schedules of Supply that clear in the HASP constitute a feasible Dispatch for the RTM at the time HASP is run, but the HASP results do not constitute a final Schedule for Generating Units because these resources may be adjusted non-economically in the RTD if necessary to manage Congestion and clear Supply and Demand. Self-Schedules submitted for Generating Units that clear in the HASP will be issued HASP Advisory Schedules. Scheduling Coordinators representing Participating Intermittent Resources whose output is being used to satisfy a resource adequacy requirement must submit Self-Schedules in HASP in accordance with the forecast provided by the independent forecast service provider. The submission of a change to an ETC Self-Schedule beyond the deadline specified in Section 16.9.1, that is permitted pursuant to the terms of the applicable ETC, shall not be deemed to be an unbalanced ETC Self-Schedule for the purposes of Settlement, consistent with the ETC and TOR Self-Schedule Settlement treatment described in Section 11.5.7.

33.4 MPM For The HASP

After the Market Close of the HASP and RTM, after the CAISO has validated the Bids pursuant to Section 30.7, and prior to running the HASP optimization, the CAISO conducts the MPM process, the results of which will be utilized in the HASP optimization. Bids on behalf of Demand Response Resources, Participating Load, and Non-Generator Resources are considered in the MPM process but are not subject to Bid mitigation. The MPM process for the HASP produces results for each fifteen (15) minute interval of the Trading Hour and thus may produce up to four mitigated Bids for any given resource for the Trading Hour. The determination as to whether a Bid is mitigated in the HASP is made based on the non-competitive Congestion component of each LMP for each fifteen (15) minute interval of the applicable Trading Hour, using the methodology set forth in Sections 31.2.2 and 31.2.(3 above. If a Bid is mitigated in any of the four fifteen (15) minute intervals comprising a Trading Hour during the MPM process for the HASP, then that Bid will be treated as mitigated for the entire Trading Hour for purposes of the HASP optimization. A single mitigated Bid for the entire Trading Hour is calculated using the minimum Bid price of the four mitigated Bid curves at each Bid quantity level.

For RMR Units, RMR Proxy Bids resulting from the HASP MPM process will be utilized in both the HASP optimization and all RTM processes for each Trading Hour. For a Condition 1 RMR Unit, the use of RMR Proxy Bids is determined based on the non-competitive Congestion component of each LMP for each fifteen (15) minute interval of the applicable Trading Hour, using the methodology set forth in Section 31.2.2 above. If a Condition 2 RMR Unit is issued a Manual RMR Dispatch by the CAISO, then RMR Proxy Bids for all of the unit's Maximum Net Dependable Capacity will be considered in the MPM process. For both Condition 1 and Condition 2 RMR Units, when mitigation is triggered, a single RMR Proxy Bid for the entire Trading Hour is calculated using the same methodology described above for non-RMR Units. For a Condition 1 RMR Unit that has submitted Bids and has not been issued a Manual RMR Dispatch, to the extent that the non-competitive Congestion component of an LMP calculated in the MPM process is greater than zero, and that MPM process dispatches a Condition 1 RMR Unit at a level such that some portion of its market Bid exceeds the Competitive LMP at the RMR Unit's Location, the resource will be flagged as an RMR dispatch if it is dispatched at a level higher than the dispatch level determined by the Competitive LMP. Both Condition 1 and Condition 2 RMR Units may be issued manual RMR dispatches at any time to address local reliability needs or to resolve non-competitive constraints.

33.5 [NOT USED]

33.6 HASP Results

The CAISO publishes the binding HASP Intertie Schedules and HASP AS Awards for System Resources, as well as HASP Advisory Schedules and HASP AS Awards for internal Generating Units (which includes Pseudo-Ties of Generating Units to the CAISO Balancing Authority Area) no later than forty-five (45) minutes prior to the Trading Hour.

33.7 Ancillary Services in the HASP

After establishing the Day-Ahead Ancillary Services Awards, the CAISO will procure additional Ancillary Services needed to meet Reliability Criteria to maintain required Ancillary Services arising from changes in forecasts of Demand and resource Outages. The CAISO utilizes the HASP (for Spinning and Non-Spinning Reserve) and the RTUC to procure additional Ancillary

Services needed for this purpose for the next Trading Hour. The HASP optimization will consider the optimal mix of Ancillary Services from System Resources and from Generating Units, but only the Ancillary Service from Non-Dynamic System Resources awarded in HASP are binding. These binding Ancillary Services Awards are for the full Trading Hour for which the given HASP run applies. Generating Units and Dynamic System Resources designated in the HASP to provide Ancillary Services for the same Trading Hour receive non-binding advisory Ancillary Services awards because the CAISO will re-optimize the use of these Generating Units and Dynamic System Resources to provide Ancillary Services in a subsequent RTUC run, as described in Section 34.2. The CAISO settles the HASP Ancillary Services Awards for Non-Dynamic System Resources as provided in Section 11.10.1.2. All Operating Reserves procured in HASP are Contingency Only Operating Reserves, as described in Section 30.5.2.6. Scheduling Coordinators submitting Ancillary Services Bids for Non-Dynamic System Resources in the HASP must also submit an Energy Bid under the same Resource ID for the associated Ancillary Services Bid. For these Non-Dynamic System Resources, the CAISO will only use the Ancillary Services Bid in the HASP optimization and will not Schedule Energy in HASP from the Energy Bid provided under the same Resource ID as the Ancillary Services Bid. The CAISO may dispatch Energy from the Contingency Only Operating Reserves awarded to Non-Dynamic System Resources in HASP through the Real-Time Contingency Dispatch as described in Section 34.3.2.

33.8 HASP Prices For HASP Intertie Schedules

The RTUC will produce fifteen (15) minute LMPs for the four (4) fifteen (15) minute RTUC intervals for the applicable Trading Hour. The fifteen (15) minute LMPs corresponding to the Scheduling Points are then used to derive a simple average hourly price for the Settlement of hourly Intertie Schedules at each Scheduling Point. The RTUC also produces fifteen (15) minute ASMPs for the four (4) fifteen (15) minute intervals for the next Trading Hour. The CAISO uses these fifteen (15) minute ASMPs to derive a simple average hourly price for the Settlement of hourly HASP AS Awards. The RTUC run will also produce fifteen (15) minute Shadow Prices for each of the Intertie constraint for the four (4) fifteen (15) minute intervals for the applicable

~~Trading Hour. These fifteen (15) minute Shadow Prices are then used to derive a simple average hourly price for charging hourly Intertie AS Awards providers for Congestion at the applicable intertie. HASP Intertie Schedules and HASP AS Awards are settled in accordance with Section 11.4 and 11.10.1.2, respectively.~~

~~33.8.1 Eligibility To Set The HASP Intertie LMP~~

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

~~33.9 Cessation Of The HASP~~

~~If, despite the variation of any time requirement or omission of any step, the CAISO is unable to operate the HASP, the CAISO may abort the HASP and perform all required functions through the RTM processes.~~

~~**34. Real-Time Market**~~

~~The RTM is the market conducted by the CAISO during any given Operating Day in which Scheduling Coordinators may provide Real-Time Imbalance Energy and Ancillary Services. The Real-Time Market consists of the Real-Time Unit Commitment (RTUC),~~ the Short-Term Unit Commitment (STUC~~) and the Real-Time Dispatch (RTD) processes. The Short-Term Unit Commitment (STUC) runs once per hour near the top of the hour and utilizes the SCUC optimization to commit Medium Start, Short Start and Fast Start Units to meet the CAISO Demand Forecast.~~), (4) the Fifteen Minute Market (FMM), and (5) the Real-Time Dispatch (RTD).

The CAISO shall dispatch all resources, including Participating Load and Proxy Demand Resource, pursuant to submitted Bids or pursuant to the provisions below on Exceptional Dispatch.

34.1 Inputs To The Real-Time Market

The CAISO utilizes the following data and information as inputs in conducting the Real-Time Market:

34.1.1 Day-Ahead Market Results as Inputs to the Real-Time Market

All of the Real-Time Market processes utilize results produced by the Day-Ahead Market for each Trading Hour of the Trading Day, including the combined commitments contained in the Day-Ahead Schedules, Day-Ahead Ancillary Services Awards, and RUC Awards. Although the RTM utilizes such results as an input to the RTM and the transactions associated with those DAM results are settled based on the relevant DAM prices, such transactions are not deemed performed until the Real-Time.

34.1.2 Market Model and System Information

The CAISO utilizes the Base Market Model used in the Day-Ahead Market and adjusted as described in 27.5.1 and 27.5.6, and other system information provided through the State Estimator output, resource outage and derate/rerate information in conducting all of the Real-Time Market processes. Updates to the Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 used in all of the Real-Time Market processes include current estimates of real-

time unscheduled flow at the Interties. The CAISO utilizes the most up-to-date Base Market Model and system information throughout the Real-Time Market processes to the extent feasible.

34.1.3 Bids in The Real-Time Market

Scheduling Coordinators may submit Bids, including Self-Schedules, for Supply that the CAISO shall use for the Real-Time Market, starting from the time Day-Ahead Schedules are posted, which is approximately 1:00 p.m., unless the posting of the Day-Ahead Market results are delayed for reasons specified in Section 31.6, until seventy-five (75) minutes prior to each applicable Trading Hour in the Real-Time. Scheduling Coordinators can submit Bids in the form of: (1) an Economic Bid for a Schedule in the RTM; (2) a Self-Schedule for acceptance to the RTM; (3) a Self-Schedule Hourly Block for acceptance in the HASP; (4) a Variable Energy Resource Self-Schedule for the RTM; (5) an Economic Hourly Block Bid for acceptance in the HASP; or (6) an Economic Hourly Block Bid with Intra-Hour Option for acceptance in the HASP and the FMM. This includes Self-Schedules by Participating Load that is modeled using the Pumped-Storage Hydro Unit. Scheduling Coordinators may not submit Bids, including Self-Schedules, for CAISO Demand in the ~~ In Real-Time, resources are required to follow Real-Time Dispatch Instructions~~RTM. Scheduling Coordinators may submit Bids, including Self-Schedules, for exports at Scheduling Points in the RTM. The rules for submitted Bids specified in Section 30 apply to Bids submitted to the RTM. Scheduling Coordinators may not submit Virtual Bids to the Real-Time Market, although Virtual Awards from the DAM are settled for their liquidated positions based on prices from the FMM.~~ In any given Trading Hour, the STUC may commit resources for the third fifteen-minute interval of the current Trading Hour and extending into the next four (4) Trading Hours. The RTUC runs every fifteen (15) minutes and utilizes the SCUC optimization to commit Fast Start and some Short Start Units and to procure any needed AS on a fifteen-minute basis. In any given Trading Hour, the RTUC may commit resources in the four to seven subsequent fifteen-minute intervals, depending on when during the hour the run occurs. Not all resources committed in a given STUC or RTUC run will necessarily receive CAISO commitment instructions immediately, because during the Trading Day the CAISO may issue a commitment instruction to a resource only at the latest possible time that allows the resource to be ready to

~~provide Energy when it is expected to be needed. The RTD uses a Security Constrained Economic Dispatch (SCED) algorithm every five minutes throughout the Trading Hour to determine optimal Dispatch Instructions to balance Supply and Demand. Updates to the Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 used in the RTM optimization include current estimates of real-time unscheduled flow at the Interties. In any given five-minute interval, the RTD optimization looks ahead over multiple five-minute intervals, but the CAISO issues Dispatch Instructions only for the next target five-minute interval. The RTUC, STUC and RTD processes of the RTM use the same Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 used in the DAM and the HASP, subject to any necessary updates of the Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6 pursuant to changes in grid conditions after the DAM has run.~~ In the case of Multi-Stage Generating Resources, the RTM procedures will optimize Transition Costs in addition to the Start-Up and Minimum Load Costs. If a Scheduling Coordinator submits a Self-Schedule or a Submission to Self-Provide Ancillary Services for a given MSG Configuration in a given Trading Hour, all of the RTM processes will consider the Start-Up Cost, Minimum Load Cost, and Transition Cost associated with any Economic Bids for other MSG Configurations as incremental costs between the other MSG Configurations and the self-scheduled MSG Configuration. In such cases, incremental costs are the additional costs incurred to transition or operate in an MSG Configuration in addition to the costs associated with the self-scheduled MSG Configuration.

34.1 ~~Inputs To The~~ .4 Real-Time Validation of Schedules and Bids

After the Market Close of the Real-Time Market, the CAISO performs a validation process consistent with the provisions set forth in Section 30.7 and the following additional rules. The CAISO will insert a Generated Bid to cover any RUC Award or Day-Ahead Schedule in the absence of any Self-Schedule or Economic Bid components, or to fill in any gaps between any Self-Schedule Bid and any Economic Bid components to cover a RUC Award or Day-Ahead Schedule for use in the RTM. Schedules and Bids submitted to the RTM to supply Energy and Ancillary Services will be considered in the various RTM processes, including the MPM process, the HASP, the STUC, the RTUC, the FMM and the RTD.

34.1.5 Mitigating Bids in the RTM

After the Market Close of the RTM, after the CAISO has validated the Bids pursuant to Section 30.7 and Section 34.1.4, and prior to conducting any other RTM processes, the CAISO conducts a MPM process. The results are used in the RTM optimization processes. Bids on behalf of Demand Response Resources, Participating Load, and Non-Generator Resources are considered in the MPM process but are not subject to Bid mitigation. The MPM process produces results for each fifteen (15) minute interval of the Trading Hour and thus may produce up to four mitigated Bids for any given resource for the Trading Hour. The determination as to whether a Bid is mitigated is made based on the non-competitive Congestion component of each LMP for each fifteen (15) minute interval of the applicable Trading Hour, using the methodology set forth in Sections 31.2.2 and 31.2.3 above. If a Bid is mitigated in the MPM process for the first fifteen (15) minute interval for a Trading Hour, the mitigated Bid will be utilized for all market applications for that first fifteen (15) minute interval. If a Bid is not mitigated in the first fifteen (15) minute interval, the CAISO will still mitigate that Bid in subsequent fifteen (15) minute intervals of the Trading Hour if the MPM runs for the subsequent intervals determine that mitigation is needed. For each Trading Hour, any Bid mitigated in a prior fifteen (15) minute interval of that Trading Hour will continue to be mitigated in subsequent intervals of that Trading Hour and may be further mitigated as determined in the MPM runs for any subsequent fifteen (15) minute interval. For HASP mitigation, a single mitigated Bid for the entire Trading Hour is calculated using the minimum Bid price of the four mitigated Bid curves at each Bid quantity level. For RMR Units, RMR Proxy Bids resulting from the MPM process will be utilized in all RTM optimization processes for each Trading Hour. For a Condition 1 RMR Unit, the use of RMR Proxy Bids is determined based on the non-competitive Congestion component of each LMP for each fifteen (15) minute interval of the applicable Trading Hour, using the methodology set forth in Section 31.2.2 above. If a Condition 2 RMR Unit is issued a Manual RMR Dispatch by the CAISO, then RMR Proxy Bids for all of the unit's Maximum Net Dependable Capacity will be considered in the MPM process. For both Condition 1 and Condition 2 RMR Units, when mitigation is triggered, a RMR Proxy Bid is calculated using the same methodology described above for non-RMR Units.

For a Condition 1 RMR Unit that has submitted Bids and has not been issued a Manual RMR Dispatch, to the extent that the non-competitive Congestion component of an LMP calculated in the MPM process is greater than zero, and that MPM process dispatches a Condition 1 RMR Unit at a level such that some portion of its market Bid exceeds the Competitive LMP at the RMR Unit's Location, the resource will be flagged as an RMR dispatch if it is dispatched at a level higher than the dispatch level determined by the Competitive LMP. Both Condition 1 and Condition 2 RMR Units may be issued manual RMR dispatches at any time to address local reliability needs or to resolve non-competitive constraints.

34.1.6 Eligible Intermittent Resources Forecast

34.1.6.1 Eligible Intermittent Resources using their own Forecast

For Eligible Intermittent Resources, including Participating Intermittent Resources, that have elected to use the resource's own forecast as specified in Section 4.8.2.1.1, the responsible Scheduling Coordinator must submit to the CAISO its forecast for the binding interval by 37.5 minutes prior to flow (the start of the applicable FMM optimization for the binding interval). If such Scheduling Coordinator does not provide such forecast to the CAISO, the CAISO will use the resource's direct telemetry MW output for Dispatch purposes. The CAISO shall use the forecast provided by the Scheduling Coordinator to establish MWh quantities to be cleared for that resource in the FMM if the resource has submitted only a Self-Schedule to the RTM. If a Scheduling Coordinator for a Variable Energy Resource submits an Economic Bid to the RTM (either with or without a Self-Schedule), then the CAISO receives and processes all Variable Energy Resources forecasts (as selected by CAISO) which establishes the upper economic limit for that resource in the FMM. Participating Intermittent Resources may elect not to use the forecast provided by the CAISO, in which case they must be certified to use their own forecast as provided in Section 4.8.2.1.1. In addition, the CAISO will not utilize the forecast it produces for the Participating Intermittent Resources using their own forecast. As provided in Section 4.8.2.1.1, the Scheduling Coordinator may submit such forecast in fifteen or five minute granularity. If the Scheduling Coordinator submits the forecast in five-minute granularity, the

CAISO will use the average of the three five-minute forecasts provided by the Scheduling Coordinator to determine the MWh to be cleared in the FMM for that resource.

34.1.6.2 Eligible Intermittent Resources using the CAISO Forecast

Eligible Intermittent Resources that have elected to use the CAISO forecast as specified in Section 4.8.2.1.2 are not required to submit a forecast for the binding interval by 37.5 minutes prior to flow. For Participating Intermittent Resources for which Scheduling Coordinators have elected to use the output forecast provided by the CAISO and have selected such a flag in their Master File, the CAISO will use the MWh forecast data the CAISO produces for such a resource at 37.5 minutes prior to the applicable FMM as follows: (a) as the MWh amounts to be to cleared for that resource in the FMM if only a Self-Schedule is submitted, and (b) as the upper economic limit for that resource in the FMM if an Economic Bid with or without a Self-Schedule is submitted. The forecast used by the CAISO will be in fifteen-minute granularity. Scheduling Coordinators representing Participating Intermittent Resources whose output is designated to satisfy a Resource Adequacy requirement must submit Variable Energy Resource Self-Schedules in the RTM in accordance with the output forecast provided by the CAISO, or an Economic Bid.

34.1.6.3 Participating Intermittent Resources under PIRP Protective Measures

For Participating Intermittent Resources that have elected PIRP Protective Measures, the CAISO will use a Self-Schedule of MWhs that is equal to the MWhs specified in the output forecast for that resource created by the CAISO ninety (90) minutes before the applicable Trading Hour to clear the resource in the RTM.

34.2 The Hour-Ahead Scheduling Process

34.2.1 The HASP Optimization

The Hour-Ahead Scheduling Process is a Real-Time Market process and a special run of the RTUC through which the CAISO accepts or rejects the following Bids submitted by Scheduling Coordinators at Scheduling Points: 1) Self-Schedule Hourly Blocks for Energy and Ancillary Services, 2) VER Self-Schedules for Energy, 3) Economic Hourly Block Bids for Energy and Ancillary Services, and 4) Economic Hourly Block Bids with Intra-Hour Option for Energy and providing an hourly schedule that can be changed at most once in the Trading Hour. The CAISO

also produces advisory Energy schedules and Ancillary Services awards. Through the HASP, the CAISO may also issue binding unit commitment instructions for any resource participating in the RTM. After the Market Close for the RTM for the relevant Trading Hour, the RTM Bids have been validated, and the RTM Bids have been mitigated and the MPM process has been performed, the CAISO then conducts the HASP optimization. The CAISO does not accept Bids for CAISO Demand for any of the Real-Time Market processes. Therefore, CAISO clears Supply Bids against the CAISO Forecast Of CAISO Demand plus submitted Export Bids, to the extent the Export Bids are selected in the MPM process. The HASP optimization also factors in forecasted unscheduled flow at the Interties, as do all the Real-Time Market processes. The HASP optimization does not produce Settlement prices for Energy or Ancillary Services and the CAISO settles all Bids accepted through the HASP based on FMM Schedules and Awards and FMM LMPs and ASMPs.

34.2.2 Treatment of Self-Schedules in HASP

The HASP optimization does not adjust submitted Self-Schedule Hourly Blocks for Energy or Ancillary Services, or Self-Scheduled Variable Energy Resources unless it is not possible to balance Supply and the CAISO Forecast Of CAISO Demand plus Export Bids and manage Congestion using the available Economic Bids, in which case the HASP performs non-economic adjustments to Self-Schedules to accommodate operational restrictions. Once accepted, Self-Schedule Hourly Blocks for Energy or Ancillary Services are considered as Self-Schedules or Self-Provision, respectively, in each of the four FMM intervals. For accepted Variable Energy Resource Self-Schedules from external resources that are not Dynamic Schedules, the CAISO uses the Self-Schedule in the HASP optimization and the Scheduling Coordinator can update the Self-Schedule based on the most current Energy forecast, if it is qualified to do so by the CAISO and the Scheduling Coordinator registers it as such in the Master File. The HASP produces advisory MWh schedules for each of the four fifteen-minute intervals for FMM Economic Bids cleared in HASP, which can vary from the MWhs schedules cleared in the FMM. The MWh quantities of Self-Schedules of Supply that clear in the HASP constitute a feasible Dispatch for the Real-Time Market at the time HASP is executed, but the HASP results do not constitute a

final Schedule for Generating Units because these resources may be adjusted for reasons other than economics in the FMM or RTD, if necessary to manage Congestion and clear Supply and Demand. The submission of a change to an ETC Self-Schedule beyond the deadline specified in Section 16.9.1, that is permitted pursuant to the terms of the applicable ETC, shall not be deemed to be an unbalanced ETC Self-Schedule for the purposes of Settlement, consistent with the ETC and TOR Self-Schedule Settlement treatment described in Section 11.5.7.~~The RTM utilizes results produced by the DAM and HASP for each Trading Hour of the Trading Day, including the combined commitments contained in the Day-Ahead Schedules, Day Ahead AS Awards, RUC Awards, HASP Intertie Schedules, HASP Self-Schedules, HASP Intertie AS Awards and the MPM that is run as part of the HASP to determine mitigated bids for each relevant Trading Hour. Virtual Bids and Virtual Awards are not used in the Real-Time Market. These results, plus the short-term Demand Forecast, Real-Time Energy Bids, Real-Time Ancillary Service Bids, updated Base Market Model adjusted as described in Sections 27.5.1 and 27.5.6, State Estimator output, resource outage and de-rate information constitute the inputs to the RTM processes. Bids submitted in HASP for all Generating Units and Participating Load shall be used in the Real-Time Market.~~

~~34.2~~

34.2.3 Ancillary Services in the HASP and FMM

All Operating Reserves procured in the Real-Time Market are Contingency Only Operating Reserves, as described in Section 30.5.2.6. Scheduling Coordinators submitting Ancillary Services Bids for Non-Dynamic System Resources in the Real-Time Market must also submit an Energy Bid under the same Resource ID for the associated Ancillary Services Bid. For these Non-Dynamic System Resources, the CAISO will only use the Ancillary Services Bid in the HASP optimization and will not Schedule Energy in the HASP, FMM, or RTD from the Energy Bid provided under the same Resource ID as the Ancillary Services Bid. The CAISO may dispatch Energy from the Contingency Only Operating Reserves awarded to Non-Dynamic System Resources in the HASP through the Real-Time Contingency Dispatch as described in Section 34.5.2.

34.2.4 HASP Results

The CAISO publishes the results of the HASP processes no later than forty-five (45) minutes prior to the Trading Hour.

34.2.5 Cessation of the HASP

If, despite the variation of any time requirement or omission of any step, the CAISO is unable to operate any or all of the HASP processes, the CAISO may abort the HASP and perform all remaining Real-Time Market processes. When the CAISO aborts the HASP, Bids for HASP Block Intertie Schedules will revert to RUC Schedules and Day-Ahead Ancillary Service Awards.

34.3 Real-Time Unit Commitment

34.3.1 RTUC Optimization

The Real-Time Unit Commitment (RTUC) process uses SCUC and is run every fifteen (15) minutes to~~: (1)~~ make commitment decisions for Fast Start and Short Start Units having Start-Up Times within the applicable time periods described below in this section~~, and (2) procure required additional Ancillary Services and calculate ASMP used for settling procured Ancillary Service capacity~~ for the next ~~fifteen-minute Real-Time Ancillary Service interval. In any fifteen (15) minute RTUC interval that falls within a time period in which a Multi-Stage Generating Resource is transitioning from one MSG Configuration to another MSG Configuration, the CAISO: (1) will not award any incremental Ancillary Services; (2) will disqualify any Day-Ahead Ancillary Services Awards; (3) will disqualify Day-Ahead qualified Submissions to Self-Provide Ancillary Services Award, and (4) will disqualify Submissions to Self-Provide Ancillary Services in RTM.~~ four to seven subsequent fifteen-minute intervals, depending on when during the hour the run occurs. For Multi-Stage Generating Resources the RTUC will issue a binding Transition Instruction separately from the binding Start-Up or Shut Down instructions. The RTUC can also be run with the Contingency Flag activated, in which case the RTUC can commit Contingency Only Operating Reserves. If RTUC is run without the Contingency Flag activated, it cannot commit Contingency Only Operating Reserves. RTUC is run at the following time intervals: (1) at approximately 7.5 minutes prior to the ~~next~~first Trading Hour, ~~in conjunction with~~to serve as the HASP run, for T-45 minutes to T+60 minutes; (2) at approximately 7.5 minutes into the current

hour for T-30 minutes to T+60 minutes; (3) at approximately 22.5 minutes into the current hour for T-15 minutes to T+60 minutes; and (4) at approximately 37.5 minutes into the current hour for T to T+60 minutes, where T is the beginning of the next ~~Trade~~Trading Hour. The HASP~~, described in Section 33,~~ is a special RTUC run that is performed at approximately 67.5 minutes before each Trading Hour and has the additional responsibility of pre-dispatching Energy and awarding Ancillary Services for ~~hourly dispatched System Resources.~~HASP Block Intertie Schedules. A Day-Ahead Schedule or RUC Schedule for an MSG Configuration that is later impacted by the resource's derate or outages, will be reconsidered in the RTUC ~~process~~and the FMM taking into consideration the impacts of the derate or outage on the available MSG Configurations. Not all resources identified as needed in a given RTUC run will necessarily receive CAISO commitment instructions immediately, because during the Trading Day the CAISO may issue a commitment instruction to a resource only at the latest possible time that allows the resource to be ready to provide Energy when it is expected to be needed.

34.3.2~~.1~~ Commitment Of Fast Start And Short Start Units

RTUC produces binding and advisory Start-Up and Shut-Down Dispatch Instructions for Fast Start and Short Start Units that have Start-Up Times that would allow the resource to be committed prior to the end of the relevant time period of the RTUC run as described in Section 34.~~2~~3.1. A Start-Up Dispatch Instruction is considered binding in any given RTUC run if the Start-Up Time of the resource is such that there would not be sufficient time for a subsequent RTUC run to Start-Up the resource. A Start-Up Instruction is considered advisory if it is not binding, such that the resource could achieve its target Start-Up Time as determined in the current RTUC run in a subsequent RTUC run based on its Start-Up Time. A Shut-Down Instruction is considered binding if the resource could achieve the target Shut-Down Time as determined in the current RTUC run in a subsequent RTUC run. A Shut-Down Dispatch Instruction is considered advisory if the resource Shut-Down Instruction is not binding such that the resource could achieve its target Shut-Down time as determined in the current RTUC run in a subsequent RTUC run. A binding Dispatch Instruction that results in a change in Commitment Status will be issued, in accordance with Section 6.3, after review and acceptance of the Start-Up Instruction by the

CAISO Operator. An advisory Dispatch Instruction changing the Commitment Status of a resource may be modified by the CAISO Operator to a binding Dispatch Instruction and communicated in accordance with Section 6.3 after review and acceptance by the CAISO Operator. Only binding and not advisory Dispatch Instructions will be issued by the CAISO. For Multi-Stage Generating Resources the CAISO will also issue binding Transition Instructions when the Multi-Stage Generating Resource must change from one MSG Configuration to another. A Transition Instruction is considered binding in any given RTUC run if the Transition Time for the Multi-Stage Generating Resource is such that there would not be sufficient time for a subsequent RTUC run to transition the resource.

34.4 Fifteen Minute Market

The CAISO conducts the Fifteen Minute Market using the second interval of each RTUC run horizon as follows: (1) at approximately 7.5 minutes prior to the first Trading Hour, for T-45 minutes to T+60 minutes where the binding interval is T-30 to T-15; (2) at approximately 7.5 minutes into the current hour for T-30 minutes to T+60 minutes where the binding interval is T-15 to T; (3) at approximately 22.5 minutes into the current hour for T-15 minutes to T+60 minutes for the binding interval T to T+15; and (4) at approximately 37.5 minutes into the current hour for T to T+60 minutes for the binding interval T+15 to T+30, where T is the beginning of the next Trading Hour. In these intervals the CAISO conducts the FMM to; (1) determine financially binding FMM Schedules and corresponding LMPs for all Pricing Nodes, including all Scheduling Points; (2) determine financially and operationally binding Ancillary Services Awards and corresponding ASMPs procure required additional Ancillary Services and calculate ASMP used for settling procured Ancillary Service capacity for the next fifteen-minute Real-Time Ancillary Service interval for all Pricing Nodes, including Scheduling Points; and (3) determine LAP LMPs that are the basis for settling Demand In any FMM interval that falls within a time period in which a Multi-Stage Generating Resource is transitioning from one MSG Configuration to another MSG Configuration, the CAISO: (1) will not award any incremental Ancillary Services; (2) will disqualify any Day-Ahead Ancillary Services Awards; (3) will disqualify Day-Ahead qualified Submissions to Self-Provide Ancillary Services Award, and (4) will disqualify Submissions to Self-Provide

Ancillary Services in RTM. Each particular FMM market optimization produces binding settlement prices for Energy and Ancillary Services for the first FMM interval in the FMM horizon but the optimization considers the advisory results from subsequent market intervals within the FMM horizon. The CAISO settles Hourly Intertie Schedules and Hourly Ancillary Services Awards accepted in the HASP as FMM Schedules and FMM Ancillary Services Awards in accordance with Section 11.5 and 11.10.1.2, respectively. In the event that a FMM run fails, the CAISO reverts to Day-Ahead Market Ancillary Services Awards and RUC Schedules results corresponding to the same interval, or the corresponding interval from the previous RTUC. The FMM will clear Supply against the CAISO Forecast Of CAISO Demand and exports. The FMM issues Energy Schedules and Ancillary Services Awards by twenty-two and a half minutes prior to the binding fifteen-minute interval.

34.4.1 Real-Time Ancillary Services Procurement

If the CAISO determines that additional Ancillary Services are required, other than those procured in the IFM, ~~HASP,~~then the ~~RTUC~~FMM will procure Ancillary Services on a fifteen (15) minute basis as necessary to meet reliability requirements and will determine Real-Time Ancillary Service interval ASMPs for such AS for the next Commitment Period. All Operating Reserves procured in the RTM are considered Contingency Only Operating Reserves. Any Ancillary Service awarded in ~~RTUC~~FMM will be taken as fixed for the three (3) five (5) minute RTD intervals of its target fifteen (15) minute interval. In the ~~RTUC~~FMM , all resources certified and capable of providing Operating Reserves that have submitted Real-Time Energy Bids shall also submit applicable Spinning or Non-Spinning Reserves Bids, respectively, depending on whether the resource is online or offline. The CAISO will utilize the ~~RTUC~~RTM to procure Operating Reserves to restore its Operating Reserve requirements in cases when: (1) Operating Reserves awarded in the IFM~~, HASP or RTUC~~ have been dispatched to provide Energy, (2) resource(s) awarded to provide Operating Reserves in the IFM~~, HASP or RTUC~~ are no longer capable of providing such awarded Operating Reserves, or (3) the Operator determines that additional Operating Reserves are necessary to maintain Operating Reserves within NERC and WECC reliability standards, and any requirements of the NRC. The CAISO will utilize the ~~RTUC~~FMM to

procure additional Regulation capacity in Real-Time in cases when: (1) resource(s) awarded to provide Regulation in the IFM~~, HASP or RTUC~~ are no longer capable of providing such awarded Regulation, or (2) the Operator determines that additional Regulation is necessary to maintain sufficient control consistent with NERC and WECC reliability standards, and any requirements of the NRC and Good Utility Practice. The ~~RTUC~~FMM will produce fifteen (15) minute ASMPs for the four (4) binding fifteen (15) minute intervals for the applicable Trading Hour. These fifteen (15) minute ASMPs are then used for the Settlement of the fifteen (15) minute AS Awards. The ~~RTUC~~FMM run will also produce fifteen (15) minute Shadow Prices for each of the Interties for the four (4) fifteen (15) minute intervals for the applicable Trading Hour. These fifteen (15) minute Shadow Prices are then used to charge for Intertie Real-Time AS Award providers for Congestion on the Interties. ~~RTUC~~FMM AS Awards are settled in accordance with 11.10.1.3.

34.~~2.3 MPM For The Real-Time Market~~

~~The CAISO performs the MPM for the Real-Time Market using validated Bids for the applicable Trading Hour pursuant to Section 30.7 as part of each RTUC. Bids on behalf of Demand Response Resources, Participating Load and Non-Generator Resources are considered in the MPM process but are not subject to Bid mitigation. The MPM process described in this Section 34.2.3 calculates mitigated Bids for use in the following Real-Time Market applications: the STUC, the RTUC and the~~ 5 Real-Time Dispatch~~. The determination as to whether a Bid is mitigated in this process is made based on the non-competitive Congestion component of each LMP for each fifteen (15) minute interval of the applicable Trading Hour, using the methodology set forth in Sections 31.2.2 and 31.2.3. If a Bid is mitigated in the MPM process for the first fifteen (15) minute interval for a Trading Hour, the mitigated Bid will be utilized for all market applications for that first fifteen (15) minute interval. If a Bid is not mitigated in the first fifteen (15) minute interval, it is subject to mitigation in subsequent fifteen (15) minute intervals of the Trading Hour as determined in the MPM runs for the subsequent intervals. For each Trading Hour, any Bid mitigated in a prior fifteen (15) minute interval of that Trading Hour will continue to be mitigated in subsequent intervals of that Trading Hour and may be further mitigated as determined in the MPM runs for any subsequent fifteen (15) minute interval.~~

~~34.3 Real-Time Dispatch~~

~~The RTD can operate in three modes: RTED, RTCD and RTMD.~~ The RTED uses a Security Constrained Economic Dispatch (SCED) algorithm every five (5) minutes throughout the Trading Hour to determine optimal Dispatch Instructions to balance Supply and Demand. The RTD can operate in three modes: RTED, RTCD and RTMD. In any given five-minute interval, the RTD optimization looks ahead over multiple five-minute intervals, but the CAISO issues Dispatch Instructions only for the next target five-minute interval.~~ The CAISO will use the Real-Time Economic Dispatch (RTED) under most circumstances to optimally dispatch resources based on their Bids. The RTED can be used to Dispatch Contingency Only Operating Reserves, pursuant to Section 34.~~8~~10, when needed to avoid an imminent System Emergency. The Real-Time Contingency Dispatch (RTCD) can be invoked in place of the RTED when a transmission or

generation contingency occurs and will include all Contingency Only Operating Reserves in the optimization. If the CAISO awards a Non-Dynamic System Resource Ancillary Services in the IFM, HASP, or ~~HASP~~FMM and issues a Dispatch Instruction in the middle of the Trading Hour for Energy associated with its Ancillary Services (Operating Reserve) capacity, the CAISO will Dispatch the Non-Dynamic System Resource to operate at a constant level until the end of the Trading Hour. If the CAISO dispatches a Non-Dynamic System Resource such that the binding interval of the Dispatch is in the next Trading Hour, the CAISO will dispatch Energy from the Non-Dynamic System Resource at a constant level until the end of the next Trading Hour. The dispatched Energy will not exceed the awarded Operating Reserve capacity for the next Trading Hour and will be at a constant level for the entire next Trading Hour. The Real Time Manual Dispatch (RTMD) will be invoked as a fall-back mechanism only when the RTED or RTCD fails to provide a feasible Dispatch. These three (3) modes of the RTD are described in Sections 34.~~3~~5.1 ~~to~~, 34.~~3~~5.2, and 34.5.3.

34.~~3~~5.1 Real-Time Economic Dispatch

RTED mode of operation for RTD normally runs every five (5) minutes starting at approximately 7.5 minutes prior to the start of the next Dispatch Interval and produces binding Dispatch Instructions for Energy for the next Dispatch Interval and advisory Dispatch Instructions for multiple future Dispatch Intervals through at least the next Trading Hour. After being reviewed by the CAISO Operator, only binding Dispatch Instructions are communicated for the next Dispatch Interval in accordance with Section 6.3. RTED will produce a Dispatch Interval LMP for each PNode for the Dispatch Interval associated with the binding Dispatch Instructions. The RTED Dispatch target is the middle of the interval between five (5) minutes boundary points. For Variable Energy Resources that forecast with 5 minute granularity, the CAISO will use the 5-minute forecast available prior to the start of the RTD optimization to determine the instructed Energy of the resource. RTD will return the 5-minute forecast value as the instructed Energy for the binding RTD interval provided that the Variable Energy Resource is optimized through the RTED.

34.~~3~~5.2 Real-Time Contingency Dispatch

34.~~3~~5.2.1 RTCD Mode

RTCD mode of operation for RTD is run in response to a significant Contingency event, such that waiting until the next normal RTD run is not adequate and/or Operating Reserves identified as Contingency Only need to be activated in response to the event. The CAISO Operator may activate Operating Reserves identified as Contingency Only either on a resource specific-basis or for all such resources. When activating Contingency Only reserves in RTCD, the original Energy Bids associated with the resources providing Operating Reserve will be used for the RTCD. RTCD uses SCED to produce an optimized set of binding Dispatch Instructions for one (1) or more ten-minute Dispatch Intervals instead of a normal five-minute Dispatch Interval. Resources must respond to RTCD Dispatch Instructions as soon as possible. After being reviewed by the CAISO Operator, only binding Dispatch Instructions are communicated for the next Dispatch Interval in accordance with Section 6.3. When activating a RTCD and returning to normal RTED run after a RTCD run, five-minute Dispatch Interval LMPs will be produced for each PNode based on the last available price from either the RTCD or normal RTED run relative to a five-minute target Dispatch Interval.

34.~~3~~5.2.2 RTDD Mode

RTDD is a special mode of the RTCD available to the CAISO Operator when 300 MW or more of capacity is needed to respond to a significant Contingency event. RTDD will not use SCED. Instead, RTDD will give Dispatch priority to Energy Bids from Operating Reserve capacity over Energy Bids from non-Operating Reserve capacity. RTDD will dispatch the Operating Reserve capacity in merit order and will then dispatch the non-Operating Reserve capacity in merit order based on available MW within the capacity's ten-minute ramping capability. As with the RTCD mode, in the RTDD mode, the CAISO Operator may activate Operating Reserves identified as Contingency Only either on a resource-specific basis or for all such resources. Resources must respond to RTDD Dispatch Instructions as soon as possible. During each ten-minute Dispatch Interval in which RTDD is employed, the Energy Bid of the highest-priced resource dispatched under RTDD will be used to set the Market Clearing Price on a system-wide basis for all

resources dispatched under RTDD. The Market Clearing Price will not reflect Transmission Losses or Transmission Constraints.

34.~~3~~5.3 Real-Time Manual Dispatch

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

34.~~4~~ 6 Short-Term Unit Commitment

~~At~~Once per hour, near the top of each Trading Hour, immediately after the FMM and the RTUC ~~run~~for the same interval is completed~~,~~ the CAISO performs an approximately five (5) hour Short-Term Unit Commitment (STUC) run using SCUC and the CAISO Forecast ~~of~~Of CAISO Demand to commit Medium Start Units and Short Start Units with Start-Up Times greater than the time period covered by the RTUC described in Section 34.3. In any given Trading Hour, the STUC may commit resources for the third fifteen-minute interval of the current Trading Hour and extending into the next four (4) Trading Hours. ~~2.~~ The STUC looks ahead over a period of at least three (3) hours beyond the Trading Hour for which the RTUC optimization was run, and will utilize Bids available from other CAISO Markets for that Trading Hour for these additional hours. The CAISO revises these replicated Bids each time the hourly STUC is run, to utilize the most recently available Bids. Not all resources identified for need as a given STUC run will necessarily

receive CAISO commitment instructions immediately, because during the Trading Day the CAISO may issue a commitment instruction to a resource only at the latest possible time that allows the resource to be ready to provide Energy when it is expected to be needed. A Start-Up Instruction produced by STUC is considered binding if the resource could not achieve the target Start-Up Time as determined in the current STUC run in a subsequent RTUC or STUC run as a result of the Start-Up Time of the resource. A Start-Up Instruction produced by STUC is considered advisory if it is not binding, such that the resource could achieve its target start time as determined in the current RTUC run in a subsequent STUC or RTUC run based on its Start-Up Time. A binding Dispatch Instruction produced by STUC that results in a change in Commitment Status will be issued, in accordance with Section 6.3, after review and acceptance of the Start-Up Instruction by the CAISO Operator. The STUC will only decommit a resource to the extent that resource's physical characteristics allow it to be cycled in the same approximately five (5) hour look-ahead time period for which it was previously committed. STUC does not produce Locational Marginal Prices for Settlement. A Day-Ahead Schedule or RUC Schedule for an MSG Configuration that is later impacted by the resource's derate or outages, will be reconsidered in the STUC process taking into consideration the impacts of the derate or outage on the available MSG Configurations.

34.~~5~~7 General Dispatch Principles

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

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

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

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

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

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

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

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

(7) Through Start-Up Instructions the CAISO may instruct resources to start up or shut down, or may reduce Load for Participating Loads and Proxy Demand Resources, over the forward-looking time period for the RTM based on submitted Bids, Start-Up Costs and Minimum Load Costs, Pumping Costs and Pump Shut-Down Costs, as appropriate for the resource, or for Multi-Stage Generating Resource as appropriate for the applicable MSG Configuration, consistent with operating characteristics of the resources that the SCED is able to enforce. In making Start-Up or Shut-Down decisions in the RTM, the CAISO may factor in limitations on number of run hours or Start-Ups of a resource to avoid exhausting its maximum number of run hours or Start-Ups during periods other than peak loading conditions;

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

(9) The RTM optimization may result in resources being shut down consistent with their Bids and operating characteristics provided that: (a) the resource does not need to be on-line to provide Energy, (b) the resource is able to start up within the applicable time periods of the processes that comprise the RTM, (c) the Generating Unit is not providing Regulation or Spinning Reserve, and (d) Generating Units online providing Non-Spinning Reserve may be shut down if they can be brought up within ten (10) minutes as such resources are needed to be online to provide Non-Spinning Reserves;

(10) For resources that are both providing Regulation and have submitted Energy Bids for the RTM, Dispatch Instructions will be based on the Regulation Ramp Rate of the resource rather than the Operational Ramp Rate if the Dispatch Operating Point remains within the Regulating

Range. The Regulating Range will limit the Ramping of Dispatch Instructions issued to resources that are providing Regulation;

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

(12) The CAISO may issue Transition Instructions to instruct resources to transition from one MSG Configuration to another over the forward-looking time period for the RTM based on submitted Bids, Transition Costs and Minimum Load Costs, as appropriate for the MSG Configurations involved in the MSG Transition, consistent with Transition Matrix and operating characteristics of these MSG Configurations. The RTM optimization will factor in limitations on Minimum Run Time and Minimum Down Time defined for each MSG configuration and Minimum Run Time and Minimum Down Time at the Generating Unit or Dynamic Resource-Specific System Resource.

34.~~6~~8 Dispatch ~~of Dispatch~~Instructions to Units, Participating Loads, and PDR

The CAISO may issue Dispatch Instructions covering:

(a) Ancillary Services;

(b) Energy, which may be used for:

(i) Congestion relief;

(ii) provision of Imbalance Energy; or

(iii) replacement of an Ancillary Service;

(c) agency operation of Generating Units, Participating Loads, Proxy Demand Resources, or Interconnection schedules, for example:

(i) output or Demand that can be Dispatched to meet Applicable Reliability Criteria;

(ii) Generating Units that can be Dispatched for Black Start;

(iii) Generating Units that can be Dispatched to maintain governor control regardless of their Energy schedules;

(d) the operation of voltage control equipment applied on Generating Units as described in this CAISO Tariff;

(e) MSS Load following instructions provided to the CAISO, which the CAISO incorporates to create their Dispatch Instructions;

(f) necessary to respond to a System Emergency or imminent emergency; or

(g) Transition Instructions.

34.~~7~~9 Utilization Of The Energy Bids

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

34.~~8~~10 Dispatch Of Energy From Ancillary Services

The CAISO may issue Dispatch Instructions to Participating Generators, Participating Loads, Proxy Demand Resources, (via communication with the Scheduling Coordinators of Demand Response Providers) System Units and System Resources contracted to provide Ancillary Services (either procured through the CAISO Markets, Self-Provided by Scheduling Coordinators, or dispatched in accordance with the RMR Contract) for the Supply of Energy. During normal operating conditions, the CAISO shall Dispatch those Participating Generators, Participating Loads, Proxy Demand Resources, System Units and System Resources that have contracted to provide Spinning and Non-Spinning Reserve, except for those reserves designated as Contingency Only, in conjunction with the normal Dispatch of Energy. Contingency Only reserves are Operating Reserve capacity that have been designated, either by the Scheduling Coordinator

or the CAISO, as available to supply Energy in the Real-Time only in the event of the occurrence of an unplanned Outage, a Contingency or an imminent or actual System Emergency. The CAISO may designate any reserve not previously identified as Contingency Only by Scheduling Coordinator as Contingency Only reserves, as necessary to maintain NERC and WECC reliability standards, including any requirements of the NRC. In the event of an unplanned Outage, a Contingency or a threatened or actual System Emergency, the CAISO may dispatch Contingency Only reserves. If Contingency Only reserves are dispatched through the RTCD, which as described in Section 34.~~3~~5.2, only Dispatches in the event of a Contingency. Such Dispatch and pricing will be based on the original Energy Bids. If Contingency Only reserves are dispatched in response to a System Emergency that has occurred because the CAISO has run out of Economic Bids when no Contingency event has occurred, the RTED will Dispatch such Contingency Only reserves using maximum Bid prices as provided in Section 39.6.1 as the Energy Bids for such reserves and will set prices accordingly. If a Participating Generator, Participating Load, System Unit or System Resource that is supplying Operating Reserve is dispatched to provide Energy, the CAISO shall replace the Operating Reserve as necessary to maintain NERC and WECC reliability standards, including any requirements of the NRC. If the CAISO uses Operating Reserve to meet Real-Time Energy requirements, and if the CAISO needs Operating Reserves to satisfy NERC and WECC reliability standards, including any requirements of the NRC, the CAISO shall restore the Operating Reserves to the extent necessary to meet NERC and WECC reliability standards, including any requirements of the NRC through either the procurement of additional Operating Reserve in the RTM or the Dispatch of other Energy Bids in SCED to allow the resources that were providing Energy from the Operating Reserve to return to their Dispatch Operating Point. The Energy Bid Curve is not used by the AGC system when Dispatching Energy from Regulation. For Regulation Up capacity, the upper portion of the resource capacity from its Regulation Limit is allocated to Regulation regardless of its Energy Bid Curve. For a resource providing Regulation Up or Operating Reserves the remaining Energy Bid Curve shall be allocated to any RTM AS Awards in the following order from higher to lower capacity where applicable: (a) Spinning Reserve; and (b) Non-Spinning Reserve. For resources providing

Regulation Up, the applicable upper Regulation Limit shall be used as the basis of allocation if it is lower than the upper portion of the Energy Bid Curve. The remaining portion of the Energy Bid Curve, if there is any, shall constitute a Bid for RTM Energy. For Regulation Down capacity, the lower portion of the resource capacity from its applicable Regulation Limit is allocated to Regulation regardless of its Energy Bid Curve.

34.~~9~~11 Exceptional Dispatch

The CAISO may issue Exceptional Dispatches for the circumstances described in this Section 34.~~9~~11, which may require the issuance of forced Shut-Downs, forced Start-Ups, or forced MSG Transitions and shall be consistent with Good Utility Practice. Dispatch Instructions issued pursuant to Exceptional Dispatches shall be entered manually by the CAISO Operator into the Day-Ahead or RTM optimization software so that they will be accounted for and included in the communication of Day-Ahead Schedules and Dispatch Instructions to Scheduling Coordinators. Exceptional Dispatches are not derived through the use of the IFM or RTM optimization software and are not used to establish the LMP at the applicable PNode. The CAISO will record the circumstances that have led to the Exceptional Dispatch. Except as provided in this Section 34.~~9~~11, the CAISO shall consider the effectiveness of the resource along with Start-Up Costs, Transition Costs, and Minimum Load Costs when issuing Exceptional Dispatches to commit a resource to operate at Minimum Load. When the CAISO issues Exceptional Dispatches for Energy, the CAISO shall also consider Energy Bids, if available and as appropriate. In accordance with Good Utility Practice, the CAISO shall make CPM designations of Eligible Capacity for an Exceptional Dispatch by applying the following additional criteria in the order listed:

(1) the effectiveness of the Eligible Capacity at meeting the designation criteria specified in Section 43.2;

(2) the capacity costs associated with the Eligible Capacity;

(3) the quantity of a resource's available Eligible Capacity, based on a resource's PMin, relative to the remaining amount of capacity needed;

(4) the operating characteristics of the resource, such as dispatchability, Ramp Rate, and load-following capability; and

(5) whether the resource is subject to restrictions as a Use-Limited Resource.

In applying these selection criteria, the goal of the CAISO will be to issue Exceptional Dispatches on a least-cost basis to resources that will be effective in meeting the reliability needs underlying the Exceptional Dispatches. In making this determination, the CAISO will apply the first criterion to identify the effective Eligible Capacity by considering the effectiveness of the resources at meeting the designation criteria for the Exceptional Dispatch and at resolving the underlying reliability need~~.~~. The CAISO will apply the second criterion by considering the cost of the effective Eligible Capacity. The CAISO will endeavor to Exceptionally Dispatch a resource at the CPM Capacity price determined in accordance with Section 43.6.1 before selecting a resource with a higher unit-specific CPM Capacity price specified under Section 43.6.2. The CAISO will endeavor to Exceptionally Dispatch resources that have specified a capacity price before designating resources that have not specified a CPM Capacity price under Section 43.6.2.1. The CAISO will apply the third criterion by considering the quantity of a resource's Eligible Capacity. The CAISO will endeavor to select a resource that has a PMin at or below the capacity that is needed to meet the reliability need before selecting a resource that has a PMin that would result in over-procurement. The CAISO will apply the fourth criterion by considering specific operating characteristics of a resource, such as dispatchability, ramp rate, and load-following capability to the extent that such characteristics are an important factor in resolving the reliability need. The CAISO will apply the fifth criterion by considering whether a resource is use-limited and whether that status may restrict its ability to be available to the CAISO in the Day-Ahead Market and Real-Time Market throughout the period for which it is being procured. To the extent that use-limited resources are capable of performing the required service for the duration of the Exceptional Dispatch, the CAISO will not unduly discriminate in favor of non-Use Limited resources when applying the selection criteria. Imbalance Energy delivered or consumed pursuant to the various types of Exceptional Dispatch is settled according to the provisions in Section 11.5.6.

34.~~9~~11.1 System Reliability Exceptional Dispatches

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

34.~~9~~11.2 Other Exceptional Dispatch

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

34.~~9~~11.3 Transmission-Related Modeling Limitations

The CAISO may also manually Dispatch resources in addition to or instead of resources with a Day-Ahead Schedule or dispatched by the RTM optimization software, during or prior to the Real-

Time as appropriate, to address transmission-related modeling limitations in the Full Network Model. Transmission-related modeling limitations for the purposes of Exceptional Dispatch, including for settlement of such Exceptional Dispatch as described in Section 11.5.6, shall consist of any FNM modeling limitations that arise from transmission maintenance, lack of Voltage Support at proper levels as well as incomplete or incorrect information about the transmission network, for which the Participating TOs have primary responsibility. The CAISO shall also manually Dispatch resources under this Section 34.~~9~~11.3 in response to system conditions including threatened or imminent reliability conditions for which the timing of the Real-Time Market optimization and system modeling are either too slow or incapable of bringing the CAISO Controlled Grid back to reliable operations in an appropriate time-frame based on the timing and physical characteristics of available resources to the CAISO.

34.~~9~~11.4 Reporting Requirements

On the fifteenth day of each month, the CAISO shall file with the Commission and post to the CAISO Website an initial report concerning the Exceptional Dispatches that occurred in the month two months prior to the month in which the report is filed. The report shall identify the frequency, volume, costs, causes, and degree of mitigation of Exceptional Dispatches during such period to the extent such data are available. On the thirtieth day of the month following the month in which the initial report is filed, the CAISO shall file with the Commission and post to the CAISO Website a revised and updated report for the same period.

34.~~10~~12 CAISO Market Adjustment To Non-Priced Quantities In The RTM

All Self-Schedules are respected by the SCED and SCUC to the maximum extent possible and are protected from curtailment in the Congestion Management process to the extent that there are effective Economic Bids that can relieve Congestion. If all Effective Economic Bids for the RTM are exhausted, all Self-Schedules between the Minimum Load and the lowest Energy level of the first Energy Bid point will be subject to uneconomic adjustments based on assigned scheduling priorities. This functionality of the optimization software is implemented through the setting of scheduling parameters as described in Section 27.4.3 and specified in Section 27.4.3.1 and the BPMs. Through this process, imports and exports may be reduced to zero, Demand may

be reduced to zero, and Generation may be reduced to a lower operating limit (or Regulation Limit) (or to a lower Regulation Limit plus any qualified Regulation Down Award or Self-Provided Ancillary Services, if applicable). Any Self-Schedules below the Minimum Load level are treated as fixed Self-Schedules and are not subject to uneconomic adjustments for Congestion Management but may be subject to decommitment via an Exceptional Dispatch if necessary as a last resort to relieve Congestion that could not otherwise be managed.

34.~~10~~12.1 Increasing Supply

The scheduling priorities as defined in the RTM optimization to meet the need for increasing Supply as reflected from higher to lower priority are as follows:

(a) Non-Participating Load reduction, exports explicitly identified in a Resource Adequacy Plan to be served by Resource Adequacy Capacity explicitly identified and linked in a Supply Plan to the exports, or Self-Schedules for exports at Scheduling Points in ~~HASP~~the RTM served by Generation from non-Resource Adequacy Capacity or from non-RUC Capacity;

(b) Self-Schedules for exports at Scheduling Points in ~~HASP~~the RTM not offered by Generation from non-Resource Adequacy Capacity or not offered by Generation from non-RUC Capacity, except those exports explicitly identified in a Resource Adequacy Plan to be served by Resource Adequacy Capacity explicitly identified and linked in a Supply Plan to the exports as set forth in Section 34.~~10~~12.1(a); and

(c) Contingency Only Operating Reserve if activated by Operator to provide Energy (as indicated by the Contingency Flag and the Contingency condition);

34.~~10~~12.2 Decreasing Supply

The scheduling priorities as defined in the RTM optimization to meet the need for decreasing Supply as reflected from higher to lower priority are as follows:

(a) Non-Participating Load increase;

(b) Reliability Must Run (RMR) Schedule (Day-Ahead manual pre-dispatch or Manual RMR Dispatches or Dispatches that are flagged as RMR Dispatches following the MPM-RRD process);

(c) Transmission Ownership Right (TOR) Self-Schedule;

(d) Existing Rights (ETC) Self-Schedule;

(~~f~~e) Regulatory Must-Run and Regulatory Must-Take (RMT) Self-Schedule;

(~~g~~f) Participating Load increase;

(~~h~~g) Day-Ahead Supply Schedule; and

(~~i~~h) Self-Schedule ~~submitted in HASP.~~

Hourly Block These dispatch priorities as defined in the RTM optimization may be superseded by operator actions and procedures as necessary to ensure reliable operations.

34.~~11~~13 Means Of Dispatch Communication

The CAISO dispatches Regulation by AGC to Participating Generators and, for Dynamic System Resources, through dedicated communication links that satisfy the CAISO's standards for external imports of Regulation. The CAISO communicates all other Dispatch Instructions electronically, except that, at the CAISO's discretion, the CAISO may communicate Dispatch Instructions by telephone, or facsimile. Scheduling Coordinators shall confirm the Dispatch Instructions that are communicated orally by repeating them to the CAISO employee providing the Dispatch Instruction. Except in the case of deteriorating system conditions or an actual or threatened System Emergency, and except for Dispatch Instructions for Regulation, the CAISO sends all Dispatch Instructions to the Scheduling Coordinator. The recipient Scheduling Coordinator shall immediately communicate the Dispatch Instruction to the operator of the resource. The CAISO may, with the prior permission of the applicable Scheduling Coordinator, communicate with and give Dispatch Instructions to the operators of the resource directly without having to communicate through their Scheduling Coordinator. The CAISO shall record the communications between the CAISO and Scheduling Coordinators relating to Dispatch Instructions in a manner that permits auditing of the Dispatch Instructions, and of the response of the resources, as applicable. In situations of deteriorating system conditions or System

Emergency, the CAISO reserves the right to communicate directly with the resource(s) as required to ensure System Reliability. Scheduling Coordinators are required to advise the CAISO immediately of any change in resource availability that prevents the recipient of a Dispatch Instruction from performing in accordance with that Dispatch Instruction.

34.~~11~~13.1 Response Required By Resources To Dispatch Instructions

Resources must:

(a) unless otherwise stated in the Dispatch Instruction, comply with a Dispatch Instruction immediately upon receipt;

(b) respond to all Dispatch Instructions in accordance with Good Utility Practice;

(c) meet voltage criteria in accordance with the provisions in the CAISO Tariff;

(d) meet any applicable Operational Ramp Rates;

(e) respond to Dispatch Instructions for Ancillary Services within the required time periods and (in the case of Participating Generators providing Regulation) respond to AGC from the EMS; and

(f) if a time frame is stated in a Dispatch Instruction, respond to a Dispatch Instruction within the stated time frame.

34.~~11~~13.2 Failure To Conform To Dispatch Instructions

In the event that, in carrying out the Dispatch Instruction, an unforeseen problem arises (relating to plant operations or equipment, personnel or the public safety), the recipient of the Dispatch Instruction must notify the CAISO or, in the case of a Generator, the relevant Scheduling Coordinator immediately. The relevant Scheduling Coordinator shall notify the CAISO of the problem immediately. If a resource is unavailable or incapable of responding to a Dispatch Instruction, or fails to respond to a Dispatch Instruction in accordance with its terms, the resource shall be considered to be non-conforming to the Dispatch Instruction unless the resource has notified the CAISO of an event that prevents it from performing its obligations within thirty (30) minutes of the onset of such event through a SLIC log entry. Notification of non-compliance via

the Automated Dispatch System (ADS) will not supplant nor serve as the official notification mechanism to the CAISO. If the resource is considered to be non-conforming as described above, the Scheduling Coordinator for the resource concerned shall be subject to Uninstructed Imbalance Energy as specified in Section 11.5.2 and Uninstructed Deviation Penalties as specified in Section 11.23. This applies whether any Ancillary Services concerned are contracted or Self-Provided. For a Non-Dynamic System Resource Dispatch Instruction prior to the Trading Hour, the Scheduling Coordinator shall inform the CAISO of its ability to conform to a Dispatch Instruction via ADS. The Non-Dynamic System Resource has the option to accept, partially accept, or decline the Dispatch Instruction, but in any case must respond within the timeframe specified in a Business Practice Manual. The Non-Dynamic System Resource can change its response within the indicated timeframe. If a Non-Dynamic System Resource does not respond within the indicated timeframe, the Dispatch Instruction will be considered declined. A decline of such a Non-Dynamic System Resource for a Dispatch Instruction received at least forty (40) minutes prior to the Trading Hour will be subject to Uninstructed Deviation Penalties as specific in Section 11.23. A decline of such a Non-Dynamic System Resource for a Dispatch Instruction received less than forty (40) minutes prior to the Trading Hour will not be subject to Uninstructed Deviation Penalties. A Non-Dynamic System Resource that only partially accepts a Dispatch Instruction is subject to Uninstructed Deviation Penalties for the portion of the Dispatch Instruction that is declined.

When a resource demonstrates that it is not following Dispatch Instructions, the RTM will no longer assume that the resource will ramp from its current output level. The RTM assumes the resource to be "non-compliant" if it is deviating its five (5)-minute Ramping capability for more than N intervals by a magnitude determined by the CAISO based on its determination that it is necessary to improve the calculation of the expected Imbalance Energy as further defined in the BPM. When a resource is identified as "non-compliant," RTM will set the Dispatch operating target for that resource equal to its actual output in the Market Clearing software such that the persistent error does not cause excessive AGC action and consequently require CAISO to take additional action to comply with reliability requirements. Such a resource will be considered to

have returned to compliance when the resource's State Estimator or telemetry value (whichever is applicable) is within the above specified criteria. During the time when the resource is "non-compliant", the last applicable Dispatch target shall be communicated to the Scheduling Coordinator as the Dispatch operating target. The last applicable Dispatch target may be (i) the last Dispatch operating target within the current Trading Hour that was instructed prior to the resource becoming "non-compliant," or (ii) the Day-Ahead Schedule, or (iii) ~~the HASP~~awarded Self-Schedule Hourly Block depending on whether the resource submitted a Bid and the length of time the resource was "non-compliant," or (iv) for a Dynamic System Resource or a Pseudo-Tie Generating Unit that is an Eligible Intermittent Resource, the most recently available telemetry for the actual output.

34.~~12~~14 Metered Subsystems

Scheduling Coordinators that represent MSSs may submit Bids for Supply of Energy to the RTM, irrespective of whether the MSS is a Load following MSS. All Bids submitted for MSS generating resources for the RTM and all Dispatch Instructions shall be generating resource-specific. MSS non-Load following resources are responsible for following Dispatch Instructions. Load following MSS Operators shall provide the CAISO with an estimate of the number of MWs the applicable generating resource(s) will be generating over the next two hours in five-minute interval resolution. The Dispatch Instructions for Load following resources are incorporated with Generation estimates provided by MSS Operators. Such MSS Load following resources can deviate from the Dispatch Instructions in Real-Time to facilitate the following of Load without being subject to the Uninstructed Deviation Penalty as further described in Section 11.23. The State Estimator will estimate all MSS Load in Real-Time and the CAISO will incorporate the information provided by the Load following MSS Operator for utilization in clearing the RTM and its Dispatch Instructions.

34.~~13~~15 Treatment Of Resource Adequacy Capacity In The RTM

Resource Adequacy Resources required to offer their Resource Adequacy Capacity in accordance with Section 40 shall be required to submit Energy Bids for: (1) all such Resource Adequacy Capacity and (2) any Ancillary Services capacity awarded or self-provided in the IFM,

HASP, or Real-Time Market. In the absence of submitted Bids, as part of the validation described in 30.7, Generated Bids will be used for Resource Adequacy Resources required to offer their Resource Adequacy Capacity in accordance with Section 40. For any capacity from a Resource Adequacy Resource not required to offer Resource Adequacy Capacity in accordance with Section 40 that was awarded or is self-providing Operating Reserves capacity in the IFM, Scheduling Coordinators must submit an Energy Bid for no less than the amount of awarded or self-provided Operating Reserves capacity above their Day-Ahead Schedule. Resource Adequacy Resources that are not required to offer their Resource Adequacy Capacity in accordance with Section 40 may voluntarily submit Energy Bids or Ancillary Services Bids. Submitted Energy Bids shall be subject to the maximum and minimum Bid requirements and Mitigation Measures as set forth in Section 39.

34.~~14~~16 Real-Time Activities In The Hour Prior To Settlement Period

34.~~14~~16.1 Confirm Interchange Transaction Schedules (ITSs)

Also in the hour prior to the beginning of the Operating Hour the CAISO will:

(a) adjust Interchange transaction schedules (ITSs) as required under Existing Contracts in accordance with the procedures in the CAISO Tariff for the management of Existing Contracts;

(b) adjust ITSs as required by changes in transfer capability of transmission paths occurring after Market Close of the ~~HASP~~RTM; and

(c) agree on ITS changes with adjacent Balancing Authorities.

34.~~15~~17 Rules For Real-Time Dispatch Of Imbalance Energy Resources

34.~~15~~17.1 Resource Constraints

The SCED shall enforce the following resource physical constraints:

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

(b) Forbidden Operating Regions. When ramping in the Forbidden Operating Region, the implicit ramp rate will be used as determined based on the time it takes for the resource to cross its Forbidden Operating Region. A resource can only be ramped through a Forbidden Operating Region after being dispatched into a Forbidden Operation Region. The CAISO will not Dispatch a resource within its Forbidden Operating Regions in the Real-Time Market, except that the CAISO may Dispatch the resource through the Forbidden Operating Region in the direction that the resource entered the Forbidden Operating Region at the maximum applicable Ramp Rate over consecutive Dispatch Intervals. A resource with a Forbidden Operating Region cannot provide Ancillary Services in a particular fifteen (15) minute Dispatch Interval unless that resource can complete its transit through the relevant Forbidden Operating Region within that particular Dispatch Interval.

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

across hours and previous Dispatch Instructions. The Start-Up Time shall be determined from the Start-Up Time function and when the resource was last shut down. The Start-Up Time shall not apply if the corresponding resource is on-line or expected to start.

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

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

(f) Operating (Spinning and Non-Spinning) Reserve. The SCED shall Dispatch Spinning and Non-Spinning Reserve subject to the limitations set forth in Section 34.~~16~~18.3.

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

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

34.~~15~~17.2 Calculation Of Dispatch Operating Points After Instructions

The RTED process shall calculate Dispatch Operating Points as follows:

(a) After the RTUC issues a Start-Up Instruction, RTED moves the Dispatch Operating Point of a resource immediately from zero (0) MW to the PMin, as defined in the Master File or as modified via SLIC, of a Generating Unit at the start of the Dispatch Interval pertaining to the Start-Up Instruction. The Dispatch Operating Point shall then be determined using the resource's applicable Operational Ramp Rate as further described in Sections 34.~~15~~17.4, 34.~~15~~17.5, and 34.~~15~~17.6.

(b) After the RTUC issues a Shut-Down Instruction, RTED shall first ramp the Dispatch Operating Point down to the PMin, as defined in the Master File or as modified via SLIC, of a Generating Unit at the end of the Dispatch Interval pertaining to the Shut-Down Instruction, using the resource's applicable Operational Ramp Rate. The Dispatch Operating Point shall then be set immediately to zero (0) MW.

(c) After the RTUC issues a Transition Instruction: (1) for MSG Configurations where the operating ranges of the two MSG Configurations do not overlap, the RTD will move the Dispatch Operating Point of the resource immediately from the boundary of the "from" MSG Configuration to the boundary of the "to" MSG Configuration, as defined in the Master File or as modified via the CAISO's outages reporting mechanism, of a Multi-Stage Generating Resource; and (2) for MSG Configurations for which the operating ranges of the two MSG Configurations do overlap, RTD will move the Dispatch Operating Point of the resource within the overlapping operating range of the MSG Configuration until the MSG Transition is complete.

34.~~15~~17.3 [NOT USED]

34.~~15~~17.4 Inter-Hour Dispatch Of Resources With Real-Time Energy Bids

Dispatch Instructions associated with the ramp between the Real-Time Market Bid in one hour and the Real-Time Market Bid in the immediately succeeding Trading Hour shall be determined

optimally by the SCED if the CAISO has Bids for either or both relevant Operating Hours. For any Operating Hour(s) for which Bids have been submitted Dispatch Instructions will be optimized such that the Dispatch Operating Point is within the Bid range(s). For any Operating Hour without submitted Bids, Dispatch Instructions will be optimized such that the Dispatch Operating Point conforms to the Schedule within the Operating Hour. Energy resulting from the Standard Ramp shall be deemed Standard Ramping Energy and will be settled in accordance with Section 11.5.1. Energy resulting from any ramp extending beyond the Standard Ramp will be deemed Ramping Energy Deviation and will be settled in accordance with Section 11.5.1. Energy delivered or consumed as a result of CAISO Dispatch of a resource's Energy Bid in one Operating Hour to a Dispatch Operating Point such that the resource cannot return to its successive Operating Hour Schedule or to an infra-marginal operating point by the beginning of the next Operating Hour is Residual Imbalance Energy and shall be settled as Instructed Imbalance Energy as provided for in Section 11.5.1 and also may be eligible for recovery of its applicable Energy Bid Costs in accordance with Section 11.8. Similarly, Energy delivered or consumed as a result of CAISO Dispatch of a resource's Energy Bid in a future Operating Hour to a Dispatch Operating Point different from its current Operating Point prior to the end of the current Operating Hour is also considered Residual Imbalance Energy and shall be settled as Instructed Imbalance Energy as provided for in Section 11.5.1 and also may be eligible for recovery of its applicable Energy Bid Costs in accordance with Section 11.8. When Ramping Energy Deviation and Residual Imbalance Energy coexist within a given Dispatch Interval, the Ramping Energy Deviation shall be the portion of Instructed Imbalance Energy that is produced or consumed within the Schedule-change band defined by the accepted ~~HASP~~RTM Bids of the two consecutive Settlement Periods; the Residual Imbalance Energy shall be the portion of Instructed Imbalance Energy that is produced or consumed outside the Schedule-change band.

34.~~15~~17.5 Inter-Hour Resources Dispatch Without Real-Time Energy Bids

Dispatch Instructions shall be issued for each Dispatch Interval as needed to prescribe the ramp between a resource's accepted Self-Schedule in one Trading Hour and its accepted Self-Schedule in the immediately succeeding Trading Hour. Such Dispatch Instructions shall be

based on the lesser of: (1) the applicable Operational Ramp Rate as provided for in Section 30.7.7 and (2) the Ramp Rate associated with the Standard Ramp. The Dispatch Instructions for Ramping of Generating Units without Real-Time Energy Bids in both Operating Hours shall ramp the resource between hourly Schedules symmetrically to the extent possible subject to the Regulation Ramping limitations across hourly boundaries in twenty (20) to sixty (60) minutes assuming Congestion can be resolved utilizing Economic Bids. The minimum twenty (20)-minute ramp is required for smooth hourly Schedule changes and is consistent with Intertie~~.~~ scheduling agreements between Balancing Authority Areas. Energy resulting from the Standard Ramp shall be deemed Standard Ramping Energy and will be settled in accordance with Section 11.5.1. Energy resulting from any ramp extending beyond the Standard Ramp will be deemed Ramping Energy Deviation and will be settled in accordance with Section 11.5.1.

34.~~15~~17.6 Intra-Hour Exceptional Dispatches

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

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

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

(c) If the new hour's Day-Ahead Schedule is beyond the Exceptional Dispatch constraint, RTM resumes the basic Ramping rules after the Exceptional Dispatch constraint is met, but limits the Ramp Rate as

necessary to ensure that the resource does not complete its ramp before ten (10) minutes after the hour.

34.~~16~~ 18 Ancillary Services In The Real-Time Market

34.~~16~~18.1 ~~[NOT USED]~~

~~34.16.2~~ Dispatch Of Self-Provided Ancillary Services

Where a Scheduling Coordinator has chosen to self-provide the whole of the additional Operating Reserve required to cover any Interruptible Imports which it has submitted through Self-Schedules in the Day-Ahead Market and has identified specific Generating Units, Participating Loads, System Units or System Resources as the providers of the additional Operating Reserve concerned, the CAISO shall Dispatch only the designated Generating Units, Participating Loads, System Units or System Resources in the event of the CAISO being notified that the on demand obligation is being curtailed. The Scheduling Coordinator scheduling an Interruptible Import will be responsible for Operating Reserves associated with the Interruptible Import, regardless of whether the Scheduling Coordinator is an LSE or not. For all other Submissions to Self-Provide an Ancillary Service, the Energy Bid shall be used to determine the Dispatch, subject to the limitation on the Dispatch of Spinning Reserve and Non-Spinning Reserve set forth in Section 34.~~10~~18.2.2.

34.~~16.3~~18.2 Ancillary Services Requirements For RTM Dispatch

The following requirements apply to the Dispatch of Ancillary Services in the RTM:

34.~~16.3~~18.2.1 Regulation

(a) Regulation provided from Generating Units or System Resources must meet the standards specified in this CAISO Tariff and Part A of Appendix K;

(b) The CAISO will Dispatch Regulation through the EMS, which Dispatch of Regulation by EMS does not set the RTM LMP;

(c) In the event of an unscheduled increase in system Demand or a shortfall in Generation output and Regulation margin drops, the CAISO will use

Dispatch Energy in the RTM or Dispatch Operating Reserve to restore Regulation margin; and

(d) When scheduled Operating Reserve is used for restoration of Regulation reserve, the CAISO shall arrange for the replacement of that Operating Reserve.

34.~~16.3~~182.2 Operating Reserve

(a) Spinning Reserve:

(i) Spinning Reserve provided from Generating Units and System Resources must meet the standards specified in Part B of Appendix K;

(ii) The CAISO will Dispatch Spinning Reserve as may be required to meet the Applicable Reliability Criteria;

(iii) The CAISO may Dispatch Spinning Reserve as balancing Energy to return Regulation Generating Units to their Set Points and restore full Regulation margin; and

(iv) The CAISO will Dispatch Spinning Reserve as determined by the SCED, subject to Sections 34.~~3~~4 and 34.~~8~~10.

(b) Non-Spinning Reserve:

(i) Non-Spinning Reserve provided from Generating Units, Demands, and System Resources must meet the standards specified in Part C of Appendix K;

(ii) The CAISO may Dispatch Non-Spinning Reserve in place of Spinning Reserve to meet Applicable Reliability Criteria;

(iii) The CAISO will Dispatch Non-Spinning Reserve as determined by the SCED, subject to Sections 34.~~3~~4 and 34.~~8~~10; and

(iv) The CAISO may Dispatch Non-Spinning Reserve to replace Spinning Reserve if there is a shortfall in Spinning Reserve because of a deficiency of balancing Energy.

34.~~16.3~~18.2.3 Replacement of Operating Reserve

If Operating Reserve is used for Energy, the CAISO may replace such Operating Reserve through Dispatch of additional Energy available from Energy Bids submitted ~~in the HASP for~~to the RTM or through procurement of additional reserves based on optimization of a resource's RTM Ancillary Service Bid and its Energy Bid.

34.~~16.3~~18.2.4 Voltage Support

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

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

(c) The CAISO may Dispatch each Generating Unit to increase or decrease MVar output outside of established power factor limits, but within the range of the Generating Unit's capability curve, at a price calculated in accordance with the CAISO Tariff.

(d) If Voltage Support is required in addition to that provided pursuant to Section 34.~~16.3~~18.2.4 (b) and (c), the CAISO will reduce output of Participating Generators certified in accordance with Appendix K . The CAISO will select Participating Generators in the vicinity where such additional Voltage Support is required.

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

34.~~17~~ 19 Dispatch Information And Instructions

34.~~17~~19.1 Dispatch Information To Be Supplied By The CAISO

Communication of Dispatch information provided by the CAISO shall be in accordance with Section 6.3.

34.~~17~~19.2 Dispatch Information To Be Supplied By SC

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

34.~~17~~19.3 Dispatch Information To Be Supplied By UDCs

Each UDC shall keep the CAISO informed of any change or potential change in the status of its transmission lines and station equipment at the point of Interconnection with the CAISO Controlled Grid. Each UDC shall keep the CAISO informed as to any event or circumstance in the UDC's service territory that could affect the reliability of the CAISO Controlled Grid. This would include adverse weather conditions, fires, bomb threats, etc.

34.~~17~~19.4 Dispatch Information To Be Supplied By PTOs

Each PTO shall report any change or potential change in equipment status of the PTO's transmission assets turned over to the control of the CAISO or in equipment that affects

transmission assets turned over to the control of the CAISO immediately to the CAISO (this will include line and station equipment, line protection, Remedial Action Schemes and communication problems, etc.). Each PTO shall also keep the CAISO immediately informed as to any change or potential change in the PTO's transmission system that could affect the reliability of the CAISO Controlled Grid. This would include adverse weather conditions, fires, bomb threats, etc.

Each PTO shall schedule all Outages of its lines and station equipment which are under the Operational Control of the CAISO in accordance with the appropriate procedures in Section 9.3.

Each PTO shall coordinate any requests for or responses to Forced Outages on its transmission lines or station equipment which are under the Operational Control of the CAISO directly with the appropriate CAISO Control Center as defined in Section 7.1.

34.~~17~~19.5 Dispatch Information To Be Supplied By Balancing Authorities

The CAISO and each adjacent Balancing Authority shall keep each other informed of any change or potential change in the status of the Interconnection and any changes in the Interconnection's TTC. The CAISO and each adjacent Balancing Authority shall keep each other informed of situations such as adverse weather conditions, fires, etc., that could affect the reliability of any Interconnection.

The CAISO and each adjacent Balancing Authority shall follow all applicable NERC and WECC scheduling procedures. This will include checking the Interconnection schedules for the next Settlement Period prior to the start of the Energy ramp going into that hour. The CAISO and each adjacent Balancing Authority shall check and agree on actual MWh net Interchange after the hour for the previous Settlement Period. One Balancing Authority Area shall change its actual number to reflect that of the other Balancing Authority Area in accordance with WECC standard procedures.

The CAISO and each adjacent Balancing Authority shall exchange MW, MVar, terminal and bus voltage data with each other on a four second update basis. MWh data for the previous hour shall be exchanged once per hour. All MW and MWh data for both the CAISO Balancing Authority Area and the adjacent Balancing Authority Areas must originate from the same metering equipment. All provisions in Sections 4.6.1.1(i) and 4.6.1.1 (ii) refer to information and data

obtained from metering used for Balancing Authority Area operations and not metering used for billing and Settlement.

34.~~18 [NOT USED]~~

~~34.19~~ 20 Pricing Imbalance Energy

34.~~19~~20.1 General Principles

Instructed and Uninstructed Imbalance Energy shall be paid or charged the applicable ~~Resource-Specific Settlement Interval~~FMM or RTD LMP~~ except for hourly pre-dispatched Instructed Imbalance Energy, which shall be settled as set forth in Section 11.5.2.~~. These prices are determined using the Dispatch Interval LMPs. The Dispatch Interval LMPs shall be based on the Bid of the marginal Generating Units, System Units, Participating Loads, and Proxy Demand Resources dispatched by the CAISO to increase or reduce Demand or Energy output in each Dispatch Interval as provided in Section 34.~~19~~20.2.1.

The CAISO will respond to the Dispatch Instructions issued by the SCED to the extent practical in the time available and acting in accordance with Good Utility Practice. The CAISO will record the reasons for any variation from the Dispatch Instructions issued by the SCED.

34.~~19~~20.2 Determining Real-Time LMPs

34.~~19~~20.2.1 Dispatch Interval Real-Time LMPs

34.~~19~~20.2.2 Computation

For each Dispatch Interval, the CAISO will compute updated Imbalance Energy needs and will Dispatch Generating Units, System Units, Dynamic System Resources, Participating Load, and Proxy Demand Resources according to the CAISO's SCED during that time period to meet Imbalance Energy requirements. The RTM transactions will be settled at the Dispatch Interval LMPs in accordance with Section 11.5.

34.~~19~~20.2.3 Eligibility to Set the Real-Time LMP

All Generating Units, Participating Loads, Proxy Demand Resources, Dynamic System Resources, System Units, or COGs subject to the provisions in Section 27.7, with Bids, including Generated Bids, that are unconstrained due to Ramp Rates or other temporal constraints are eligible to set the LMP, provided that (a) a Generating Unit or a Dynamic Resource-Specific

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

~~**34.19.2.4 [NOT USED]**~~

~~**34.19.2.5 Price for Uninstructed Deviations for Participating Intermittent Resources**~~

~~Deviations associated with each Participating Intermittent Resource in a Scheduling Coordinator's portfolio shall be settled as provided in Section 11.12 at the monthly weighted average Dispatch Interval LMP, as calculated in accordance with Section 11.5.4.1 at each Pnode associated with the Participating Intermittent Resource, and using the monthly weighted average with weights equal to total Real-Time Generation.~~

* * *

~~35.1 Market Validation~~

34.21 Temporary Waiver of Timing Requirements for the Real-Time Market

34.21.1 Criteria for Temporary Waiver of Timing Requirements

The CAISO may at its sole discretion implement any temporary variation or waiver of the timing requirements of this Section 34, Section 6.5.4, and Section 6.5.5 (including the omission of any step) if any of the following criteria are met:

(i) such waiver or variation of timing requirements is reasonably necessary to preserve System Reliability, prevent an imminent or threatened System Emergency or to retain Operational Control over the CAISO Controlled Grid during an actual System Emergency.

(ii) because of error or delay, the CAISO requires additional time to fulfill its responsibilities;

(iii) problems with data or the processing of data cause a delay in receiving or issuing Bids or publishing information on the CAISO's secure communication system;

(iv) problems with telecommunications or computing infrastructure cause a delay in receiving or issuing Day-Ahead Schedules or publishing information on the CAISO's secure communication system.

34.21.2 Information to be Published on Secure Communication System

If the CAISO temporarily implements a waiver or variation of such timing requirements, the CAISO will publish the following information on the CAISO's secure communication system as soon as practicable:

(i) the exact timing requirements affected;

(ii) details of any substituted timing requirements;

(iii) an estimate of the period for which this waiver or variation will apply; and

(iv) reasons for the temporary waiver or variation.

* * *

35.1 Market Validation

The CAISO shall monitor the Market Clearing software solutions for the Day-Ahead Market, the RUC process, ~~the Hour-Ahead Scheduling Process,~~ and the Real-Time Market for all market intervals to determine whether prices are calculated accurately, consistent with the provisions of the CAISO Tariff. To the extent reasonably practicable, the CAISO shall correct erroneous prices identified through such monitoring and re-run the relevant CAISO Markets prior to publication of prices on its Open Access Same-Time Information System (OASIS) or provision of prices directly to Market Participants, if applicable.

* * *

37.3.1.1 Expected Conduct

Market Participants must submit Bids for Energy, RUC Capacity and Ancillary Services and Submissions to Self-Provide an Ancillary Service from resources that are reasonably expected to be available and capable of performing at the levels specified in the Bid, and to remain available and capable of so performing based on all information that is known to the Market Participant or should have been known to the Market Participant at the time of submission. ~~HASP~~ Intertie Schedules in the RTM for import or export Energy are not subject to the foregoing requirement, but failure to deliver on such ~~HASP~~ Intertie Schedules in the RTM can be subject to referral by DMM under Section 11.1, Appendix P ~~where the failure to deliver is suspected to be a Market Violation~~.

* * *

39.7 Local Market Power Mitigation For Energy Bids

Local Market Power Mitigation is based on the assessment and designation of Transmission Constraints as competitive or non-competitive pursuant to Section 39.7.2. The local market power mitigation processes are described in Section 31.2 for the DAM~~, Section 33.4 for the HASP, and Section 34.2.3 for the RTM utilizing Default Energy Bids calculated pursuant to one of the options set forth in Section 39.7.1.~~ and Sections 34.1.5 for the RTM.

* * *

39.7.2.1 Timing of Assessments

For the DAM~~, HASP,~~ and RTM, the CAISO will make assessments and designations of whether Transmission Constraints are competitive or non-competitive as part of the MPM runs associated with the DAM~~, HASP,~~ and RTM, respectively. Only binding Transmission Constraints determined by the MPM process will be assessed in the applicable market.

39.7.2.2 Criteria

Subject to Section 39.7.3, for the DAM~~, HASP,~~ and RTM, a Transmission Constraint will be non-competitive only if the Transmission Constraint fails the dynamic competitive path assessment pursuant to this Section 39.7.2.2.

(a) Transmission Constraints for the DAM – As part of the MPM process associated with the DAM, the CAISO will designate a Transmission Constraint for the DAM as non-competitive when the fringe supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow to the Transmission Constraint. For purposes of determining whether to designate a Transmission Constraint as non-competitive pursuant to this Section 39.7.2.2(a):

(i) Counter-flow to the Transmission Constraint means the delivery of Power from a resource to the system load distributed reference bus. If counter-flow to the Transmission Constraint is in the direction opposite to the market flow of Power to the Transmission Constraint, the counter-flow to the Transmission Constraint is calculated as the shift factor multiplied by the resource's scheduled Power. Otherwise, counter-flow to the Transmission Constraint is zero.

(ii) Fringe supply of counter-flow to the Transmission Constraint means all available capacity from internal resources not controlled by the identified potentially pivotal suppliers and all internal Virtual Supply Awards not controlled by the identified potentially pivotal suppliers that provide

counter-flow to the Transmission Constraint. Available capacity reflects the highest capacity of a resource's Energy Bid adjusted for Self-Provided Ancillary Services and derates.

(iii) Demand for counter-flow to the Transmission Constraint means all internal dispatched Supply and Virtual Supply Awards that provide counter-flow to the Transmission Constraint.

(iv) Potentially pivotal suppliers mean the three (3) portfolios of net sellers that control the largest quantity of counter-flow supply to the Transmission Constraint.

(v) Portfolio means the effective available internal generation capacity under the control of the Scheduling Coordinator and/or Affiliate determined pursuant to Section 4.5.1.1.12 and all effective internal Virtual Supply Awards of the Scheduling Coordinator and/or Affiliate. Effectiveness in supplying counter-flow is determined by scaling generation capacity and/or Virtual Supply Awards by the shift factor from that location to the Transmission Constraint being tested.

(vi) A portfolio of a net seller means any portfolio that is not a portfolio of a net buyer. A portfolio of a net buyer means a portfolio for which the average daily net value of Measured Demand minus Supply over a twelve (12) month period is positive. The average daily net value is determined for each portfolio by subtracting, for each Trading Day, Supply from Measured Demand and then averaging the daily value for all Trading Days over the twelve (12) month period. The CAISO will calculate whether portfolios are portfolios of net buyers in the third month of each calendar quarter and the calculations will go into effect at the start of the next calendar quarter. The twelve (12) month period used in this calculation will be the most recent twelve (12) month period for which data is available. The specific mathematical formula used to

perform this calculation will be set forth in a Business Practice Manual. Market Participants without physical resources will be deemed to be net sellers for purposes of this Section 39.7.2.2(a)(vi).

(vii) In determining which Scheduling Coordinators and/or Affiliates control the resources in the three (3) identified portfolios, the CAISO will include resources and Virtual Supply Awards directly associated with all Scheduling Coordinator ID Codes associated with the Scheduling Coordinators and/or Affiliates, as well as all resources that the Scheduling Coordinators and/or Affiliates control pursuant to Resource Control Agreements registered with the CAISO as set forth Section 4.5.1.1.13. Resources identified pursuant to Resource Control Agreements will only be assigned to the portfolio of the Scheduling Coordinator that has control of the resource or whose Affiliate has control of the resource pursuant to the Resource Control Agreements.

(b) Transmission Constraints for the ~~HASP and~~ RTM – As part of the MPM processes associated with the ~~HASP and~~ RTM, the CAISO will designate a Transmission Constraint for the ~~HASP or~~ RTM as non-competitive when the sum of the supply of counter-flow from all portfolios of potentially pivotal suppliers to the Transmission Constraint and the fringe supply of counter-flow to the Transmission Constraint from all portfolios of suppliers that are not identified as potentially pivotal is less than the demand for counter-flow to the Transmission Constraint. For purposes of determining whether to designate a Transmission Constraint as non-competitive pursuant to this Section 39.7.2.2(b):

(i) Counter-flow to the Transmission Constraint has the meaning set forth in Section 39.7.2.2(a)(i).

(ii) Supply of counter-flow from all portfolios of potentially pivotal suppliers to the Transmission Constraint means the minimum available capacity from internal resources controlled by the identified potentially pivotal suppliers

that provide counter-flow to the Transmission Constraint. The minimum available capacity for the current market interval will reflect the greatest amount of capacity that can be physically withheld. The minimum available capacity is the lowest output level the resource could achieve in the current market interval given its dispatch in the last market interval and limiting factors including Minimum Load, Ramp Rate, Self-Provided Ancillary Services, Ancillary Service Awards (in the Real-Time Market only), and derates.

(iii) Potentially pivotal suppliers mean the three (3) portfolios of net sellers that control the largest quantity of counter-flow supply to the Transmission Constraint that can be withheld. Counter-flow supply to the Transmission Constraint that can be withheld reflects the difference between the highest capacity and the lowest capacity of a resource's Energy Bid (not taking into account the Ramp Rate of the resource), measured from the Dispatch Operating Point for the resource in the immediately preceding fifteen (15) minute FMM interval ~~of the HASP~~ (taking into account the Ramp Rate of the resource), adjusted for Self-Provided Ancillary Services and derates in determining whether to designate a Transmission Constraint as non-competitive for the ~~HASP~~RTM, or adjusted for Ancillary Service Awards and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM. In determining whether to designate a Transmission Constraint as non-competitive for the ~~HASP~~RTM, counter-flow supply to the Transmission Constraint that can be withheld also reflects the PMin of each Short Start Unit with a Start-Up Time of sixty (60) minutes or less that was off-line in the immediately preceding fifteen (15) minute interval of the ~~HASP~~FMM. In determining whether to designate a Transmission Constraint as non-competitive for the RTM,

counter-flow supply to the Transmission Constraint that can be withheld also reflects the PMin of each Short Start Unit with a Start-Up Time of fifteen (15) minutes or less that was off-line in the immediately preceding fifteen (15) minute interval.

(iv) Portfolio means the effective available internal generation capacity under the control of the Scheduling Coordinator and/or Affiliate determined pursuant to Sections 4.5.1.1.12 and 39.7.2.2(a)(vii). Effectiveness in supplying counter-flow is determined by scaling generation capacity by the shift factor from that location to the Transmission Constraint being tested.

(v) A portfolio of a net seller has the meaning set forth in Section 39.7.2.2(a)(vi).

(vi) Fringe supply of counter-flow to the Transmission Constraint means all available capacity from internal resources not controlled by the identified potentially pivotal suppliers that provide counter-flow to the Transmission Constraint. Available capacity reflects the highest capacity of a resource's Energy Bid (not taking into account the Ramp Rate of the resource), measured from the Dispatch Operating Point for the resource in the immediately preceding fifteen (15) minute interval of the ~~HASP~~FMM (taking into account the Ramp Rate of the resource), adjusted for Self-Provided Ancillary Services and derates in determining whether to designate a Transmission Constraint as non-competitive for the ~~HASP~~RTM, or adjusted for Ancillary Service Awards and derates in determining whether to designate a Transmission Constraint as non-competitive for the RTM.

(vii) Demand for counter-flow to the Transmission Constraint means all internal dispatched Supply that provides counter-flow to the Transmission Constraint.

* * *

39.7.3 Default Competitive Path Designations

The CAISO will maintain default competitive path designation sets for the Day-Ahead Market and for the ~~HASP/~~Real-Time Market, which the CAISO will use in order to determine the competitiveness or non-competitiveness of Transmission Constraints under two circumstances: (1) in the event of a failure of the CAISO Markets software to perform an assessment of whether Transmission Constraints are competitive or non-competitive pursuant to Section 39.7.2; and (2) in order to determine whether Exceptional Dispatches are related to a non-competitive Transmission Constraint for purposes of mitigation of Exceptional Dispatches of resources under Section 39.10(1).~~-~~ Default competitive path designations will be determined pursuant to the methodology set forth in this Section 39.7.3 and will be updated no less frequently than once every seven (7) days. ~~-~~Until the CAISO has developed sufficient information to develop default competitive path designations, the CAISO will continue to utilize the most recent list of competitive path designations determined prior to the effective date of this tariff provision.

* * *

39.7.3.4 Methodology for Determining ~~HASP/~~RTM Default Competitive Path Designations for Path 15 and Path 26 Transmission Constraints

The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive for purposes of determining default competitive path designations for the ~~HASP/~~RTM unless both of the following conditions are met:

(1) Congestion occurred on the Transmission Constraint in ten (10) or more of the hours for which the Transmission Constraint was tested for competitiveness pursuant to Section 39.7.2; and

(2) the Transmission Constraint was deemed competitive pursuant to Section 39.7.2 in fewer than seventy-five (75) percent of the instances in which the Transmission Constraint was binding when tested.

These calculations will be made utilizing data from the MPM for the Real-Time Market for the most recent sixty (60) Trading Days for which data is available. If the Transmission Constraint was binding during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be binding for the entire hour. If the Transmission Constraint was determined to be non-competitive during any 15-minute interval during an hour, then the Transmission Constraint will be deemed to be non-competitive for the entire hour. The CAISO will designate the Path 15 Transmission Constraint or the Path 26 Transmission Constraint as competitive if the CAISO lacks sufficient data to determine whether the occurrences set forth in Sections 39.7.3.4(1) and 39.7.3.4(2) took place on the Transmission Constraint over the sixty (60) Trading Day period.

* * *

39.10.3 Eligibility For Supplemental Revenues

Except as provided in Section 39.10.4, a resource that is committed or dispatched under Exceptional Dispatch shall be eligible for supplemental revenues only during such times that the resource meets all of the following criteria:

(i) the resource has notified the CAISO, at least seven days prior to the calendar month in which the Exceptional Dispatch occurs, that the resource has chosen to receive supplemental revenues in lieu of an Exceptional Dispatch CPM designation under Section 43.1.5;

(ii) the resource has been mitigated under Section 39.10;

(iii) the resource is not under an RMR Contract, is not designated as CPM Capacity, and is not a Resource Adequacy Resource, unless the resource is a Partial Resource Adequacy Resource or a partial CPM resource, and the Exceptional Dispatch requires non-RA Capacity or non-CPM Capacity, in which case only the capacity not committed as Resource Adequacy Capacity or CPM Capacity is eligible for supplemental revenues; and

(iv) the resource has a Bid in the IFM~~, HASP,~~ and RTM for the applicable Operating Day or Operating Hour in which the resource is committed or dispatched under Exceptional Dispatch.

* * *

40.5.1 Day Ahead Scheduling And Bidding Requirements

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

(i) Local Capacity Area Resources physically capable of operating must submit: (a) Economic Bids for Energy and/or Self- Schedules for all their Resource Adequacy Capacity and (b) Economic Bids for Ancillary Services and/or a Submission to Self-Provide Ancillary Services for all of their Resource Adequacy Capacity that is certified to provide Ancillary

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

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

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

(iv) Through the IFM co-optimization process, the CAISO will utilize available Local Capacity Area Resource Adequacy Capacity to provide Energy or Ancillary Services in the most efficient

manner to clear the Energy market, manage congestion and procure required Ancillary Services. In so doing the IFM will honor submitted Energy Self-Schedules of the Local Capacity Area Resource Adequacy Capacity of the Modified Reserve Sharing LSE unless the CAISO is unable to satisfy one hundred (100) percent of the Ancillary Services requirements. In such cases the CAISO may curtail all or a portion of a submitted Energy Self-Schedule to allow Ancillary Service-certified Local Capacity Area Resource Adequacy Capacity to be used to meet the Ancillary Service requirements. The CAISO will not curtail for the purpose of meeting Ancillary Service requirements a Self-Schedule of a resource internal to a Metered Subsystem that was submitted by the Scheduling Coordinator for that Metered Subsystem. If the IFM reduces the Energy Self-Schedule of Resource Adequacy Capacity to provide an Ancillary Service, the Ancillary Service Marginal Price for that Ancillary Service will be calculated in accordance with Section 27.1.2 using the Ancillary Service Bids submitted by the Scheduling Coordinator for the Resource Adequacy Resource or inserted by the CAISO pursuant to this Section 40.5.1, and using the resource's Generated Energy Bid to determine the Resource Adequacy Resource's opportunity cost of Energy. If the Scheduling Coordinator for the Modified Reserve Sharing LSE's Resource Adequacy Resource believes that the opportunity cost of Energy based on the Resource Adequacy Resource's Generated Energy Bid is insufficient to compensate for the resource's actual opportunity cost, the Scheduling Coordinator may submit evidence justifying the increased

amount to the CAISO and to the FERC no later than seven (7) days after the end of the month in which the submitted Energy Self-Schedule was reduced by the CAISO to provide an Ancillary Service. -The CAISO will treat such information as confidential and will apply the procedures in Section 20.4 of this CAISO Tariff with regard to requests for disclosure of such information. -The CAISO shall pay the higher opportunity costs after those amounts have been approved by FERC.

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

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

* * *

40.5.4 Consequence Of Failure To Meet Scheduling Obligation

(1) If the Scheduling Coordinator for the Modified Reserve Sharing LSE fails to submit a Self-Schedule or submit Bids equal to 115% of its hourly Demand Forecasts for each Trading Hour for the next Trading Day in the IFM and RUC, the Scheduling Coordinator will be charged a capacity surcharge of three times the price of the relevant Day-Ahead

Hourly LAP LMP in the amount of the shortfall. To the extent the Scheduling Coordinator for the Modified Reserve Sharing LSE schedules imports on one or more Scheduling Points in an aggregate megawatt amount greater than its aggregate import deliverability allocation under Section 40.4.6.2, the quantity of megawatts in excess of its import deliverability allocation will not count toward satisfying the Modified Reserve Sharing LSE's scheduling obligation, unless it clears the Day-Ahead Market.

(2) If the Scheduling Coordinator for the Modified Reserve Sharing LSE cannot fulfill its obligations under Section 40.5.1(3), the Scheduling Coordinator for the Modified Reserve Sharing LSE will be charged a capacity surcharge of two times the average of the six (6) Settlement Interval LAP prices for the hour in the amount of the shortfall. Energy scheduled in the ~~HASP~~RTM will not net against, or be used as a credit to correct, any failure to fulfill the Day-Ahead IFM hourly scheduling and RUC obligation in Section 40.5.1(1).

(3) Any Energy surcharge received by the CAISO pursuant to this Section 40.5.4 shall be allocated to Scheduling Coordinators representing other Load Serving Entities in proportion to each such Scheduling Coordinator's Measured Demand during the relevant Trading Hour(s) to the aggregate CAISO Measured Demand during the relevant Trading Hour(s).

* * *

40.6.4.3.2 Hydro and Non-Dispatchable Use-Limited Resources

Hydroelectric Generating Units, Pumping Load, and Non-Dispatchable Use-Limited Resources shall submit Self-Schedules or Bids in the Day-Ahead Market for their expected available Energy or their expected as-available Energy, as applicable, in the Day-Ahead Market and ~~HASP.~~ RTM. Such resources shall also revise their Self-Schedules or submit additional Bids

in ~~HASP~~RTM based on the most current information available regarding ~~expected~~Expected Energy deliveries.~~-~~ Hydroelectric Generating Units, Pumping Load, and Non-Dispatchable Use-Limited Resources will not be subject to commitment in the RUC process. ~~-~~The CAISO will retain discretion as to whether a particular resource should be considered a Non-Dispatchable Use-Limited Resource, and this decision will be made in accordance with the provisions of Section 40.6.4.1.

* * *

40.6.5 Additional Availability Requirements For System Resources

In the IFM, the multi-hour block constraints of a System Resource, other than a System Resource capable of submitting a Dynamic Schedule or a Resource-Specific System Resource, are honored in the optimization. ~~-~~Such a resource that is also a Resource Adequacy Resource must be capable of hourly scheduling by the CAISO in RUC if it is not fully scheduled in the IFM. ~~-~~If such a Resource Adequacy Resource is scheduled in the RUC, the CAISO will schedule the resource in the ~~HASP~~RTM for each hour of the resource's RUC schedule without regard to the multi-hour block constraint that was submitted to the IFM.~~-~~ For an existing System Resource that provides Resource Adequacy Capacity through a call-option that expires prior to the close of the IFM, such a System Resource listed on a Resource Adequacy Plan must be reported to the CAISO for consideration in the Extremely Long-Start Commitment Process.

* * *

40.6.7 Release Of Long Start Units

Long Start Units not committed in the Day-Ahead Market will be released from any further obligation to submit Self-Schedules or Bids for the relevant Operating Day. Scheduling Coordinators for Long Start Units are not precluded from self-committing the unit after the Day-Ahead Market and submitting a Self-Schedule for Wheeling-Out in the ~~HASP~~RTM, unless precluded by terms of their contracts.

* * *

40.6.8.1.2 Price Taker Option

The price taker option is a Generated Bid of $0/MWh plus the CAISO's estimate of the applicable grid management charge per MWh based on the gross amount of MWh scheduled in the DAM and ~~HASP~~RTM.

* * *

40.6.11 Curtailment Of Exports In Emergency Situations

At its sole discretion, the CAISO may curtail exports from Resource Adequacy Capacity to prevent or alleviate a System Emergency. ~~-~~An Export Bid or a Self-Schedule to provide exports included in a binding Schedule accepted in the IFM or ~~HASP~~RTM will not be distinguished from a Demand Bid or Self-Schedule to serve Load within the CAISO Balancing Authority Area included in a binding Schedule accepted in the IFM or ~~HASP~~RTM for purposes of curtailment under this Section, except as consistent with Good Utility Practice.

* * *

41.5.1 Day-Ahead And ~~HASP~~RTM RMR Dispatch

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

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

The Energy to be delivered for each Trading Hour pursuant to the RMR Dispatch Notice an RMR Dispatch in the IFM or Real-Time shall be referred to as the RMR Energy.~~-~~ Scheduling Coordinators may submit Bids in the DAM or the ~~HASP~~RTM for RMR Units operating under Condition 1 of the RMR Contract in accordance with the bidding rules applicable to non-RMR

Units. A Bid submitted in the DAM or the ~~HASP~~RTM for a Condition 1 RMR Unit shall be deemed to be a notice of intent to substitute a market transaction for the amount of MWh specified in each Bid for each Trading Hour pursuant to Section 5.2 of the RMR Contract. In the event the CAISO issues an RMR Dispatch Notice or an RMR Dispatch in the IFM or Real-Time Market for any Trading Hour, any MWh quantities cleared through the MPM shall be considered as a market transaction in accordance with the RMR Contract. RMR Units operating as Condition 2 RMR Units may not submit Bids until and unless the CAISO issues an RMR Dispatch Notice or issues an RMR Dispatch in the IFM, in which case a Condition 2 RMR Unit shall submit Bids in accordance with the RMR Contract in the next available market for the Trading Hours specified in the RMR Dispatch Notice or Day-Ahead Schedule.

* * *

41.5.3 RMR Units And Ancillary Services Requirements

The CAISO may call upon RMR Units in any amounts that the CAISO has determined is necessary at any time after the issuance of Day-Ahead Schedules for the Trading Day if: (i) the CAISO determines that it requires more of an Ancillary Service than it has been able to procure, except that the CAISO shall not be required to accept Ancillary Services Bids that exceed the price caps specified in Section 39 or any other FERC-imposed price caps; and (ii) the CAISO has notified Scheduling Coordinators of the circumstances existing in this Section 41.5.3, and after such notice, the CAISO determines that a bid insufficiency condition in accordance with the RMR Contract exists in the ~~HASP~~RTM and the CAISO requires more of an Ancillary Service. The CAISO must provide the notice specified in sub paragraph (ii) of this Section 41.5.3 as soon as possible after the CAISO determines that additional Ancillary Services are needed for which Bids are not available. The CAISO may only determine that a Bid insufficiency exists after the Market Close of the ~~HASP~~RTM, unless an earlier determination is required in order to accommodate the RMR Unit's operating constraints. For the purposes of this Section 41.5.3, a Bid insufficiency exists in ~~HASP~~RTM if, and only if: (i) Bids in the ~~HASP~~RTM for the particular Ancillary Service that can be used to satisfy that particular Ancillary Services requirement that remain after first procuring the megawatts of the

Ancillary Service that the CAISO had notified Scheduling Coordinators it would procure in the HASP ("remaining Ancillary Services requirement") represent, in the aggregate, less than two times such remaining Ancillary Services requirement; or (ii) there are less than two unaffiliated bidders to provide such remaining Ancillary Services requirement. If the CAISO determines that a Bid insufficiency condition exists as described in this Section 41.5.3, the CAISO may nonetheless accept available Bids if it determines in its sole discretion that the prices specified in the Bids and the Energy Bid Curves created by the Bids indicate that the Scheduling Coordinators were not attempting to exercise market power.

* * *

Appendix A

Master Definition Supplement

* * *

- Alert, Warning Or Emergency (AWE) Notice

A CAISO operations communication issued to Market Participants and the public, under circumstances and in a form specified in CAISO Operating Procedures, when the operating requirements of the CAISO Controlled Grid are marginal because of Demand exceeding forecast, loss of major Generation sources, or loss of transmission capacity that has curtailed imports into the CAISO Balancing Authority Area, or if insufficient Bids for the Supply of Energy and Ancillary Services have been submitted in the ~~HASP~~RTM for the CAISO Balancing Authority Area.

* * *

- Ancillary Service Award Or AS Award

The notification by the CAISO indicating that a Bid to supply an Ancillary Service has been selected to provide such service in the DAM~~, HASP,~~ or RTM.

* * *

- Ancillary Service Schedule Or AS Schedule

The notification by the CAISO indicating that a Submission to Self-Provide an Ancillary Service has been selected to provide such service in the DAM~~, HASP,~~ or RTM.

* * *

- Bid Cost Recovery (BCR) Eligible Resources

Those resources eligible to participate in the Bid Cost Recovery as specified in Section 11.8, which include Generating Units, System Units, System Resources with RTM Economic bids, Participating Loads, and Proxy Demand Resources. A System Resource that has a Schedule that results from Bids submitted in violation of Section 30.5.5 shall not be a Bid Cost Recovery Eligible Resource for any Settlement Interval that occurs during the time period covered by the Schedule that results from Bids submitted in violation of Section 30.5.5. Accepted Self-Schedule Hourly Blocks, cleared Economic Hourly Block Bids, and cleared Economic Hourly Block Bids with Intra-Hour Option are not eligible to participate in Bid Cost Recovery in the Real-Time Market.

* * *

- CAISO Markets

Any of the markets administered by the CAISO under the CAISO Tariff, including, without limitation, the DAM, ~~HASP,~~ RTM, transmission, and Congestion Revenue Rights.

- CAISO Markets Processes

The MPM, IFM, RUC, HASP, STUC, FMM, RTUC, and RTD. ~~HASP is an hourly run of the RTUC.~~

* * *

- Commitment Interval

The fifteen minute period of time for which the CAISO commits resources or procures Ancillary Services through the ~~Real-Time Unit Commitment process~~FMM.

* * *

- Decline Monthly Charge – Exports

A charge that applies to the aggregate of a Scheduling Coordinator's HASP Block Intertie Schedules for Energy exports that are not delivered in a Trading Month, as determined pursuant to Section 11.31.1.

- Decline Monthly Charge – Imports

A charge that applies to the aggregate of a Scheduling Coordinator's HASP Block Intertie

Schedules for Energy imports that are not delivered in a Trading Month, as determined pursuant to Section 11.31.1.

- Decline Potential Charge – Exports

A potential charge that is calculated for any HASP Block Intertie Schedule for an Energy export when the HASP Block Intertie Schedule is not delivered for any reason, which potential charge and its applicability are determined pursuant to Section 11.31.

- Decline Potential Charge – Imports

A potential charge that is calculated for any HASP Block Intertie Schedule for an Energy import when the HASP Block Intertie Schedule is not delivered for any reason, which potential charge and its applicability are determined pursuant to Section 11.31.

- Decline Threshold Percentage – Imports/Exports

The rate at which Scheduling Coordinators may fail to deliver imports or exports in accordance with HASP Block Intertie Schedules without incurring Decline Monthly Charges – Imports or Decline Monthly Charges – Exports, as measured by the respective percentages of HASP Block Intertie Schedules for import or export MWh quantities that the Scheduling Coordinator does not deliver during a Trading Month. The Decline Threshold Percentage – Imports/Exports is ten percent (10%).

- Decline Threshold Quantity – Imports/Exports

The MWh quantity of HASP Block Intertie Schedules for imports or exports of Energy that a Scheduling Coordinator may fail to deliver during a Trading Month without incurring Decline Monthly Charges – Imports or Decline Monthly Charges – Exports. The Decline Threshold Quantity – Imports/Exports is 300 MWh.

* * *

- ~~Derate Energy~~[Not Used]

~~Extra-marginal IIE, exclusive of Standard Ramping Energy, Ramping Energy Deviation, Residual Imbalance Energy, MSS Load Following Energy, and Real-Time Minimum Load Energy produced or consumed due to Minimum Load overrates or PMax derates. Derate Energy is produced above the higher of the Day-Ahead Schedule, the registered Minimum Load, or the HASP Intertie~~

~~Schedule, and below the lower of the overrated Minimum Load and the Dispatch Operating Point, or consumed below the lower of the Day-Ahead Schedule or the HASP Intertie Schedule, and above the higher of the derated PMax or the Dispatch Operating Point. There could be two Derate Energy slices, one for the Minimum Load overrate, and one for the PMax derate. Derate Energy does not overlap with Standard Ramping Energy, Ramping Energy Deviation, Residual Imbalance Energy, Real-Time Minimum Load Energy, Exceptional Dispatch Energy, or Optimal Energy, but it may overlap with Day-Ahead Scheduled Energy, HASP Scheduled Energy, and MSS Load Following Energy. Derate Energy is settled as described in Section 11.5.1, and it is not included in BCR as described in Section 11.8.4.~~

* * *

- Eligible Intermittent Resource

~~A~~A Variable Energy Resource that is a Generating Unit or Dynamic System Resource subject to a Participating Generator Agreement, Net Scheduled PGA, Dynamic Scheduling Agreement for Scheduling Coordinators, or Pseudo-Tie Participating Generator Agreement ~~that is powered by wind or solar energy, except for a de minimis amount of Energy from other sources.~~.

* * *

- Exceptional Dispatch

A Dispatch Instruction issued for the purposes specified in Section 34.~~9.~~ 11. Energy from Exceptional Dispatches shall not set any ~~Dispatch Interval~~FMM or RTD LMP.

* * *

- ~~Exceptional Dispatch Energy~~**[Not Used]**

~~Extra-marginal IIE, exclusive of Standard Ramping Energy, Ramping Energy Deviation, Residual Imbalance Energy, MSS Load Following Energy, Real-Time Minimum Load Energy, and Derate Energy, produced or consumed due to Exceptional Dispatch Instructions that are binding in the relevant Dispatch Interval. Without MSS Load following, Exceptional Dispatch Energy is produced above the LMP index and below the lower of the Dispatch Operating Point or the Exceptional Dispatch Instruction, or consumed below the LMP index and above the higher of the Dispatch Operating Point or the Exceptional Dispatch Instruction. The LMP index is the capacity~~

~~in the relevant Energy Bid that corresponds to a Bid price equal to the relevant LMP. Exceptional Dispatch Energy does not overlap with Standard Ramping Energy, Ramping Energy Deviation, Residual Imbalance Energy, Real-Time Minimum Load Energy, Derate Energy, or Optimal Energy, but it may overlap with Day-Ahead Scheduled Energy, HASP Scheduled Energy, and MSS Load Following Energy. Exceptional Dispatch Energy is settled as described in Section 11.5.6, and it is not included in BCR as described in Section 11.8.4.~~

* * *

- Expected Energy

The total Energy that is expected to be generated or consumed by a resource, based on the Dispatch of that resource, as calculated by the Real-Time Market (RTM), and as finally modified by any applicable Dispatch Operating Point corrections. Expected Energy includes the Energy scheduled in the IFM, and it is calculated for the applicable Trading Day. Expected Energy is calculated for Generating Units, System Resources, Resource-Specific System Resources, Participating Loads, and Proxy Demand Resources. The calculation is based on the Day-Ahead Schedule and the Dispatch Operating Point trajectory for the three-hour period around the target Trading Hour (including the previous and following hours), the applicable ~~Real-Time~~FMM or RTD LMP for each Dispatch Interval of the target Trading Hour, and any Exceptional Dispatch Instructions. Energy from Non-Dynamic System Resources is converted into ~~HASP Intertie~~FMM Schedules. Expected Energy is used as the basis for Settlements.

* * *

- Fast Start Unit

A Generating Unit that has a Start-Up Time less than two hours and can be committed in the ~~RTUC~~FMM and STUC.

* * *

- Fifteen Minute Market (FMM)

A Real-Time market procedure conducted throughout the Operating Day in fifteen-minute increments prior to the RTD, to clear Bids for Energy and Ancillary Services from imports and exports, internal Supply and CAISO Forecast Of CAISO Demand, as further specified in Section

34.5.

* * *

- FMM AS Award

An award of Ancillary Services established through the Fifteen Minute Market.

- FMM Derate Energy

Extra-marginal FMM IIE, exclusive of FMM Minimum Load Energy produced or consumed due to Minimum Load overrates or PMax derates. FMM Derate Energy is produced above the higher of the Day-Ahead Schedule or the registered Minimum Load and below the lower of the overrated Minimum Load and the FMM Schedule, or consumed below the Day-Ahead Schedule and above the higher of the derated PMax or the FMM Schedule. There could be two FMM Derate Energy slices, one for the Minimum Load overrate, and one for the PMax derate. FMM Derate Energy does not overlap with FMM Minimum Load Energy, FMM Exceptional Dispatch Energy, or FMM Optimal Energy, but it may overlap with Day-Ahead Scheduled Energy and MSS Load Following Energy. FMM Derate Energy is settled as described in Section 11.5.1, and it is not included in BCR as described in Section 11.8.4.

- FMM Exceptional Dispatch Energy

Extra-marginal FMM IIE, exclusive of FMM Minimum Load Energy, and FMM Derate Energy, produced or consumed due to FMM Exceptional Dispatch Instructions that are binding in the relevant Dispatch Interval. Without MSS Load following, FMM Exceptional Dispatch Energy is produced above the LMP index and below the lower of the FMM Schedule or the FMM Exceptional Dispatch Instruction, or consumed below the LMP index and above the higher of the FMM Schedule or the FMM Exceptional Dispatch Instruction. The LMP index is the capacity in the relevant Energy Bid that corresponds to a Bid price equal to the relevant LMP. FMM Exceptional Dispatch Energy does not overlap with FMM Minimum Load Energy, FMM Derate Energy, or FMM Optimal Energy, but it may overlap with Day-Ahead Scheduled Energy, RTD Optimal Energy, and MSS Load Following Energy. FMM Exceptional Dispatch Energy is settled as described in Section 11.5.6, and it is not included in BCR as described in Section 11.8.4.

* * *

- FMM IIE Settlement Amount

The payment due a Scheduling Coordinator for positive FMM Instructed Imbalance Energy or the charge assessed on a Scheduling Coordinator for negative FMM Instructed Imbalance Energy, as calculated pursuant to Section 11.5.1.1

- FMM Instructed Imbalance Energy (FMM IIE)

The portion of Imbalance Energy resulting from Day-Ahead Schedules and FMM Schedules determined pursuant to Section 11.5.1.

- FMM Minimum Load Energy

FMM IIE produced due to the Minimum Load of a Generating Unit that is committed in the RUC or the FMM and does not have a Day-Ahead Schedule or of a Constrained Output Generator (COG) that is committed in the IFM with a Day-Ahead Schedule below the registered Minimum Load. If the resource is committed in the FMM for Load following by an MSS Operator, the FMM Minimum Load Energy is accounted as MSS Load Following Energy instead. FMM Minimum Load Energy is FMM IIE above the Day-Ahead Schedule (or zero if there is no Day-Ahead Schedule of Energy) and below the registered Minimum Load. FMM Minimum Load Energy does not overlap with any other Expected Energy type. FMM Minimum Load Energy is settled as described in Section 11.5.1, and it is included in BCR as described in Section 11.8.4.1.2. FMM IIE that is consumed when a resource that is scheduled in the DAM is shut down in the FMM is accounted as FMM Optimal Energy and not as FMM Minimum Load Energy.

- FMM MSS Price

1) The Hourly LAP price for the MSS when the MSS internal metered Demand exceeds the MSS internal measured Generation; or 2) the weighted average of the FMM LMPs for all applicable PNodes within the relevant MSS when MSS internal measured Generation exceeds MSS internal Measured Demand where weighting factors for computing the weighted average are based on the measured Energy of all Generation at the corresponding PNodes.

- FMM Non-Overlapping Optimal Energy

The portions of FMM Optimal Energy that are not FMM Overlapping Optimal Energy, which are indexed against the relevant Energy Bid and sliced by Energy Bid price.

- FMM Optimal Energy

Any remaining FMM IIE after accounting for all other FMM IIE subtypes. FMM Optimal Energy does not overlap with FMM Minimum Load Energy, FMM Derate Energy, and FMM Exceptional Dispatch Energy, but it may overlap with Day-Ahead Scheduled Energy, and MSS Load Following Energy. FMM Optimal Energy is indexed against the relevant Energy Bid and sliced by service type, depending on the AS capacity allocation on the Energy Bid. FMM Optimal Energy is also divided into FMM Overlapping Optimal Energy and FMM Non-Overlapping Optimal Energy. Any FMM Optimal Energy slice below or above the Energy Bid has no associated Energy Bid price, and it is not included in BCR as described in Section 11.5.

- FMM Overlapping Optimal Energy

The portion of FMM Optimal Energy that overlaps with MSS Load Following Energy.

- FMM Schedule

The binding output of the FMM resulting from Bids submitted to the RTM. The portion of a HASP Block Intertie Schedule for either Energy or Ancillary Services that becomes financially binding shall constitute a FMM Schedule.

* * *

- Forced Outage

An Outage for which sufficient notice cannot be given to allow the Outage to be factored into the Day-Ahead Market~~, HASP~~ or RTM bidding processes.

* * *

- HASP Advisory Schedule

The ~~non-binding~~ output of the HASP ~~as it pertains to the Real-Time Market.~~

* * *

- [Not Used] ~~HASP **And RTM Congestion Credit**~~

~~A credit provided to Scheduling Coordinators to offset any HASP and RTM Congestions Charges that would otherwise be applied to the valid and balanced portions of any ETC or TOR Self-Schedules in the HASP and the Real-Time Market as provided in Section 11.5.7.~~

* * *

- [Not Used] ~~HASP AS Award~~

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

- ~~HASP Bid~~[Not Used]

~~A Bid received in HASP that can be used in the MPM conducted in HASP, the RTUC, STUC, or the RTD.~~

- ~~HASP Inter-SC Trade Period~~[Not Used]

~~The period commencing at midnight (0000 hours) on the applicable Trading Day and ending at forty-five (45) minutes prior to the start of the applicable Operating Hour, during which time the CAISO will accept from Scheduling Coordinators Inter-SC Trades of Energy for the HASP, Inter-SC Trades of Ancillary Services, and Inter-SC Trades of IFM Load Uplift Obligations.~~

- ~~HASP Intertie LMP~~[Not Used]

~~The average of four (4) 15-minute interval LMPs at~~Block Intertie ~~Scheduling Points over a Trading Hour.~~Schedule.

- HASP Block Intertie Schedule

The ~~binding output of the HASP including accepted Bids for imported Energy or Ancillary Services and associated LMPs and ASMPs~~output of the HASP resulting from accepted Self-Schedule Hourly Blocks and awarded Economic Hourly Block Bids (but excluding an Economic Hourly Block Bid with Intra-Hour option). A HASP Block Intertie Schedule can include Energy and AS. HASP Block Intertie Schedules, as modified after accepted, are settled at the applicable FMM LMP and FMM ASMPs. HASP Block Intertie Schedules are advisory only in that they may be curtailed by the CAISO for Reliability reasons. Otherwise, the MWH quantity of a HASP Block Intertie Schedule is financially binding.

- [Not Used] ~~HASP Scheduled Energy~~

~~IIE from a Non-Dynamic System Resource, exclusive of Real-Time Pumping Energy and Real-Time Minimum Load Energy, produced or consumed due to hourly scheduling in the HASP. HASP Scheduled Energy is produced above the higher of the Day-Ahead Schedule or the Minimum Load, and below the HASP Intertie Schedule, or consumed below the Day-Ahead Schedule and above the HASP Intertie Schedule. In the latter case, HASP Scheduled Energy~~

~~overlaps with Day-Ahead Scheduled Energy; HASP Scheduled Energy does not overlap with Real-Time Pumping Energy or Real-Time Minimum Load Energy, but it may overlap with other IIE subtypes. HASP Scheduled Energy is indexed against the relevant Energy Bid and sliced by service type, depending on the Ancillary Services capacity allocation on the Energy Bid, and by Energy Bid price. HASP Scheduled Energy slices are settled as described in Section 11.4, and they are included in BCR as reflected in Section 11.8.4; provided that if any HASP Scheduled Energy slice below or above the Energy Bid has no associated Energy Bid price, it is not included in BCR as described in Section 11.8.4. For Non-Dynamic System Resources that are designated as MSS Load following resources, HASP Scheduled Energy is considered as MSS Load Following Energy.~~

* * *

Hour-Ahead Scheduling Process (HASP)

The process conducted by the CAISO beginning at seventy-five minutes prior to the Trading Hour through which the CAISO conducts the ~~following activities: 1) accepts Bids for Supply of Energy, including imports, exports and Ancillary Services imports to be supplied during the next Trading Hour that apply to the MPM, RTUC, STUC, and RTD; 2) conducts the MPM on the Bids that apply to the RTUC, STUC, and RTD; and 3) conducts the RTUC for the hourly pre-dispatch of Energy and Ancillary Services.~~activities specified in Section 34.2.

* * *

- ~~Imbalance Energy~~**[Not Used]**

~~The deviation of Supply or Demand from Day-Ahead Schedule, positive or negative, as measured by metered Generation, metered Load, or Real-Time Interchange Schedules.~~

* * *

- **[Not Used]** ~~**Instructed Imbalance Energy (IIE)**~~

~~The portion of Imbalance Energy resulting from Dispatch Instructions and HASP Intertie Schedules.~~

* * *

- Inter-SC Trade Period

Either the Day-Ahead Inter-SC Trade Period or the ~~HASP~~RTM Inter-SC Trade Period.

* * *

- Market Clearing

The act of conducting any of the ~~process~~processes used by the CAISO to determine LMPs, Day-Ahead Schedules, RUC Awards or AS Awards, HASP Block Intertie Schedules, FMM Schedules and Dispatch Instructions based on Supply Bids and Demand Bids or CAISO Demand Forecast.

* * *

- Market Close

The time after which the CAISO is no longer accepting Bids for its CAISO Markets which: 1) for the DAM is 10:00 A.M. Pacific Time of the Day-Ahead; and 2) for ~~the HASP and the~~ RTM is approximately seventy-five minutes prior to the Operating Hour.

* * *

- Market Power Mitigation - RRD

The two-optimization run process conducted in both the Day-Ahead Market and the ~~HASP~~RTM that determines the need for the CAISO to employ market power mitigation measures or Dispatch RMR Units.

* * *

- MSS Load Following Energy

RTD IIE, exclusive of Standard Ramping Energy, Ramping Energy Deviation, and Residual Imbalance Energy, produced or consumed due to Load following by an MSS. MSS Load Following Energy is the RTD IIE that corresponds to the algebraic Qualified Load Following Instruction, relative to the Day-Ahead Schedule. MSS Load Following Energy does not coexist with ~~HASP Scheduled~~FMM Optimal Energy, and it does not overlap with Standard Ramping Energy, Ramping Energy Deviation, or Residual Imbalance Energy, but it may overlap with Day-Ahead Scheduled Energy, RTD Derate Energy, RTD Exceptional Dispatch Energy, ~~Real-Time Self-Scheduled Energy,~~ and RTD Optimal Energy. MSS Load Following Energy is settled as provided in Section 11.5.1, and it is not included in BCR as described in Section 11.8.4.

* * *

- Net Procurement

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

* * *

- [Not Used] ~~Non-Overlapping Optimal Energy~~

~~The portions of Optimal Energy that are not Overlapping Optimal Energy, which are indexed against the relevant Energy Bid and sliced by Energy Bid price.~~

* * *

- Non-priced Quantity

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

* * *

- Non-Spinning Reserve Cost

~~-~~The revenues paid to the suppliers of the total awarded Non-Spinning Reserve capacity in the Day-Ahead Market~~, HASP,~~ and Real-Time Market, minus, ~~(ii)~~ the payments rescinded due to either the failure to conform to CAISO Dispatch Instructions or the unavailability of the Non-Spinning Reserves under Section 8.10.8.

* * *

- Operational Adjustment

The difference between the Energy scheduled in the Balancing Authority Area check-out process for Scheduling Points and the FMM Schedule for Non-Dynamic System Resources ~~and the sum of Dispatch Interval IIE~~.

* * *

- ~~Optimal Energy~~**[Not Used]**

* * *

- Persistent Deviation Metric

A threshold metric used to evaluate a resource's change in output between Settlement Intervals relative to the change in Dispatch by the CAISO between Settlement Intervals. The Persistent Deviation Metric is applied by Settlement Interval and is applied for the ~~twelve ten~~twenty-four five-minute Settlement Intervals that comprise the previous two Trading Hours. Thus, the evaluation window is a rolling two hours, incrementing in hourly Settlement Intervals. The Persistent Deviation Metric for each Settlement Interval (t) is measured as the ratio of: (1) Metered Energy in the prior Settlement Interval (t-1), less the Metered Energy in the given Settlement Interval (t); and (2) Metered Energy in the prior Settlement Interval (t-1), less the Expected Energy in the given Settlement Interval (t), and less the Regulation Energy in the given Settlement Interval (t).

* * *

- PIRP Protective Measures

The temporary Settlement treatment delineated in Section 11.12.1 that is provided to Participating Intermittent Resources that qualify to receive such treatment under Section 4.8.1 and that complete their election to receive such treatment no later than thirty (30) days after the effective date of Section 4.8.1

* * *

- Real-Time Congestion Offset

For each Settlement Period of the ~~HASP and~~ RTM, the CAISO shall calculate the Real-Time Congestion Offset as the difference of 1) the sum of the products of the total of the Demand Imbalance Energy and Virtual Supply liquidated as demand in the RTM and the RTM MCC at the relevant Location; and 2) the sum of the products of the total of the Supply Imbalance Energy and

Virtual Demand liquidated as supply in the RTM, and the RTM MCC at the relevant Location; including also the sum of RTM ~~and HASP~~ Congestion Charges for Intertie Ancillary Services Awards, and excluding the ~~HASP and~~ RTM Congestion Credit for ETCs and TORs calculated as provided in Section 11.5.7.1.~~-~~ The Real-Time Congestion Offset is allocated as provided in Section 11.5.4.2.

* * *

- Real-Time Market (RTM)

The spot market conducted by the CAISO using SCUC and SCED in the Real-Time~~, after the HASP is completed,~~ which includes the ~~RTUC~~HASP, FMM, STUC and the RTD for the purpose of Unit Commitment, Ancillary Service procurement, Congestion Management and Energy procurement based on Supply Bids and CAISO Forecast ~~of~~Of CAISO Demand.

- Real-Time Market Pumping Bid Cost

For the applicable Settlement Interval, the Pumping Cost submitted to the CAISO in the ~~HASP or~~ RTM divided by the number of Settlement Intervals in a Trading Hour, as further provided in Section 11.8.4.1.4.

* * *

- [Not Used]

- [Not Used]

- [Not Used]

- [Not Used].

- Real-Time Unit Commitment (RTUC)

An application of the RTM that runs every 15 minutes and commits Fast Start Units and Medium Start Units using the SCUC to adjust from Day-Ahead Schedules and HASP Advisory Schedules.

* * *

- [Not Used]

* * *

- RTD Derate Energy

Extra-marginal RTD IIE, exclusive of FMM IIE, Standard Ramping Energy, Ramping Energy

Deviation, Residual Imbalance Energy, MSS Load Following Energy, and RTD Minimum Load Energy produced or consumed due to Minimum Load overrates or PMax derates. RTD Derate Energy is produced above the higher of the FMM Schedule or the registered Minimum Load, and below the lower of the overrated Minimum Load and the Dispatch Operating Point, or consumed below the lower of the FMM Schedule, and above the higher of the derated PMax or the Dispatch Operating Point. There could be two RTD Derate Energy slices, one for the Minimum Load overrate, and one for the PMax derate. RTD Derate Energy does not overlap with FMM IIE, Standard Ramping Energy, Ramping Energy Deviation, Residual Imbalance Energy, RTD Minimum Load Energy, RTD Exceptional Dispatch Energy, or RTD Optimal Energy, but it may overlap with Day-Ahead Scheduled Energy and MSS Load Following Energy. RTD Derate Energy is settled as described in Section 11.5.1, and it is not included in BCR as described in Section 11.8.4.

- RTD Exceptional Dispatch Energy

Extra-marginal RTD IIE, exclusive of FMM IIE, Standard Ramping Energy, Ramping Energy Deviation, Residual Imbalance Energy, MSS Load Following Energy, RTD Minimum Load Energy, and RTD Derate Energy, produced or consumed due to RTD Exceptional Dispatch Instructions that are binding in the relevant Dispatch Interval. Without MSS Load following, RTD Exceptional Dispatch Energy is produced above the LMP index and below the lower of the Dispatch Operating Point or the RTD Exceptional Dispatch Instruction, or consumed below the LMP index and above the higher of the Dispatch Operating Point or the RTD Exceptional Dispatch Instruction. The LMP index is the capacity in the relevant Energy Bid that corresponds to a Bid price equal to the relevant LMP. RTD Exceptional Dispatch Energy does not overlap with FMM IIE, Standard Ramping Energy, Ramping Energy Deviation, Residual Imbalance Energy, RTD Minimum Load Energy, RTD Derate Energy, or RTD Optimal Energy, but it may overlap with Day-Ahead Scheduled Energy and MSS Load Following Energy. RTD Exceptional Dispatch Energy is settled as described in Section 11.5.6, and it is not included in BCR as described in Section 11.8.4.

- RTD IIE Settlement Amount

The payment due a Scheduling Coordinator for positive RTD Instructed Imbalance Energy or the charge assessed on a Scheduling Coordinator for negative RTD Instructed Imbalance Energy, as calculated pursuant to Section 11.5.1.2.

- RTD Imbalance Energy

The deviation of Supply or Demand from FMM Schedule, positive or negative, as measured by metered Generation, metered Load, or Real-Time Interchange Schedules. RTD Imbalance Energy is composed of RTD Instructed Imbalance Energy and Uninstructed Imbalance Energy.

- RTD Instructed Imbalance Energy (RTD IIE)

The portion of Imbalance Energy resulting from Dispatch Instructions and FMM Schedules.

- RTD Minimum Load Energy

RTD IIE, exclusive of Standard Ramping Energy, Ramping Energy Deviation, and Residual Imbalance Energy, produced due to the Minimum Load of a Generating Unit that is committed in the RUC or the RTM and does not have a Day-Ahead Schedule or ~~of~~ a Constrained Output Generator (COG) that is committed in the IFM with a Day-Ahead Schedule below the registered Minimum Load. If the resource is committed in RTM for Load following by an MSS Operator, the ~~Real-Time~~RTD Minimum Load Energy is accounted as MSS Load Following Energy instead. ~~Real-Time~~RTD Minimum Load Energy is RTD IIE above the Day-Ahead Schedule (or zero if there is no Day-Ahead Schedule of Energy) and below the registered Minimum Load. ~~Real-Time~~ RTD Minimum Load Energy does not overlap with any other Expected Energy type. ~~Real-Time~~RTD Minimum Load Energy is settled as described in Section 11.5.1, and it is included in BCR as described in Section 11.8.4.1.2. RTD IIE that is consumed when a resource that is scheduled in the DAM is shut down in the RTM is accounted as ~~HASP Scheduled Energy or~~RTD Optimal Energy and not as ~~Real-Time~~RTD Minimum Load Energy.

* * *

~~- Real-Time~~**- RTD MSS Price**

1) The RTD LAP price for the MSS when the MSS internal metered Demand exceeds the MSS internal measured Generation; or 2) the weighted average of the RTD LMPs for all applicable PNodes within the relevant MSS when MSS internal measured Generation exceeds MSS internal

Measured Demand where weighting factors for computing the weighted average are based on the measured Energy of all Generation at the corresponding PNodes.

- RTD Non-Overlapping Optimal Energy

The portions of RTD Optimal Energy that are not RTD Overlapping Optimal Energy, which are indexed against the relevant Energy Bid and sliced by Energy Bid price.

- RTD Optimal Energy

Any remaining RTD IIE after accounting for all other RTD IIE subtypes. RTD Optimal Energy does not overlap with FMM Optimal Energy Standard Ramping Energy, Ramping Energy Deviation, Residual Imbalance Energy, RTD Minimum Load Energy, RTD Derate Energy, and RTD Exceptional Dispatch Energy, but it may overlap with Day-Ahead Scheduled Energy, and MSS Load Following Energy. RTD Optimal Energy is indexed against the relevant Energy Bid and sliced by service type, depending on the AS capacity allocation on the Energy Bid. Optimal Energy is also divided into RTD Overlapping Optimal Energy and RTD Non-Overlapping Optimal Energy. Any RTD Optimal Energy slice below or above the Energy Bid has no associated Energy Bid price, and it is not included in BCR as described in Section 11.5.1.1.

- RTD Overlapping Optimal Energy

The portion of RTD Optimal Energy that overlaps with MSS Load Following Energy.

- RTD Pumping Energy

RTD IIE from a Participating Load Pumped-Storage Hydro Unit or Pumping Load, exclusive of Standard Ramping Energy and Ramping Energy Deviation, consumed below the Day-Ahead Schedule when dispatched in pumping mode, or produced from pumping operation due to pumping level reduction in Real-Time Dispatch, including pump shut-down. ~~Real-Time~~RTD Pumping Energy does not overlap with any other RTD Expected Energy type. ~~Real-Time~~ RTD Pumping Energy is settled as described in Section 11.5.1, and it is included in BCR as described in Section 11.8.4.1.4.

~~**- Real-Time Self-Scheduled Energy**~~

~~The slice of Non-Overlapping Optimal Energy that corresponds to the Real-Time total Self-Schedule.~~

~~**- Real-Time Settlement Interval MSS Price**~~

~~1) The Real-Time LAP price for the MSS when the MSS internal metered Demand exceeds the MSS internal measured Generation; or 2) the weighted average of the Real-Time LMPs for all applicable PNodes within the relevant MSS when MSS internal measured Generation exceeds MSS internal Measured Demand where weighting factors for computing the weighted average are based on the measured Energy of all Generation at the corresponding PNodes.~~

~~**- Real-Time Unit Commitment (RTUC)**~~

~~An application of the RTM that runs every 15 minutes and commits Fast Start Units and Medium Start Units using the SCUC to adjust from Day-Ahead Schedules and HASP Intertie Schedules.~~

* * *

~~**- Resource-Specific Settlement Interval LMP**~~

~~The LMP at a PNode used for settlement of IIE, calculated as the IIE-weighted average, excluding the IIE weight for Residual Imbalance Energy, Energy from HASP Intertie Schedules, and Energy from Black Start and Voltage Support, of the individual LMPs for Dispatch Intervals within the given Settlement Interval for a resource, and if there is no Instructed Imbalance Energy, then it is calculated as the simple average of the individual LMPs for the Dispatch Intervals within the given Settlement Interval for a resource.~~

* * *

* * *

- RTM Congestion Credit

A credit provided to Scheduling Coordinators to offset any RTM Congestions Charges that would otherwise be applied to the valid and balanced portions of any ETC or TOR Self-Schedules in the Real-Time Market as provided in Section 11.5.7.

* * *

- RTM Inter-SC Trade Period

The period commencing at midnight (0000 hours) on the applicable Trading Day and ending at forty-five (45) minutes prior to the start of the applicable Operating Hour, during which time the

CAISO will accept from Scheduling Coordinators Inter-SC Trades of Energy to the RTM, Inter-SC Trades of Ancillary Services, and Inter-SC Trades of IFM Load Uplift Obligations.

- RTM MCL Credit For Eligible TOR Self-Schedules

A credit provided to Scheduling Coordinators pursuant to Section 17.3.3 to offset any ~~HASP and~~ RTM Marginal Cost of Losses that would otherwise be applied to the valid and balanced portions of any TOR Self-Schedule in the IFM as provided in Section 11.5.7.2.

* * *

- ~~RTUC~~[Not Used]

~~Real-Time Unit Commitment~~

* * *

* * *

- Schedule

A Day-Ahead Schedule~~, a HASP Advisory Schedule,~~ or a ~~HASP Intertie~~FMM Schedule.

*** * ***

- Security Constrained Unit Commitment (SCUC)

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

* * *

- Self-Provided Ancillary Services

A Submission to Self-Provide Ancillary Services in the Day-Ahead Market~~, HASP,~~ or Real-Time Market that has been accepted by the CAISO. Acceptance will occur prior to Ancillary Service Bid evaluation in the relevant market and indicates that the CAISO has determined the submission is feasible with regard to resource operating characteristics and regional constraints and is qualified to provide the Ancillary Service in the market for which it was submitted. Self-

Provided Ancillary Services consist of self-provided Regulation Up reserves, self-provided Regulation Down reserves, self provided Spinning Reserves, and self-provided Non-Spinning Reserves.

* * *

- Self-Schedule

The Bid component that indicates the quantities in MWhs with no specification of a price that the Scheduling Coordinator is submitting to the CAISO, which indicates that the Scheduling Coordinator is a Price Taker, Regulatory Must-Run Generation or Regulatory Must-Take Generation, which includes ETC and TOR Self-Schedules ~~and~~, Self-Schedules for Converted Rights, and Variable Energy Resource Self-Schedules.

* * *

- Set Point

Scheduled operating level for each Generating Unit or other resource scheduled to run in the ~~HASP~~FMM Schedule and ~~HASP Awards~~FMM Award.

* * *

- Settlement Interval

The five-minute time period ~~equal to or a multiple of the Dispatch Interval,~~ over which the CAISO settles cost compensation amounts or deviations in Generation and Demand in ~~CAISO Markets.~~the RTM.

* * *

- Spinning Reserve Cost

~~The portion of unloaded synchronized resource capacity that is immediately responsive to system frequency and that is capable of being loaded in ten (10) minutes, and that is capable of running for at least thirty (30) minutes from the time it reaches its award capacity.~~

* * *

~~**- Tier 1 UIE**~~

~~The quantity of Uninstructed Deviation from the resource's Instructed Imbalance Energy.~~

~~**- Tier 2 UIE**~~

~~The quantity of Uninstructed Deviation from the resource's Day-Ahead Schedule.~~

* * *

The revenues paid to the suppliers of the total awarded Spinning Reserve capacity in the Day-Ahead Market and Real-Time Market for the Settlement Period, minus the payments rescinded in the Settlement Period due to the unavailability of the Spinning Reserve under any of the provisions of Section 8.10.2.

* * *

- Tolerance Band

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

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

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

* * *

- Uninstructed Imbalance Energy (UIE)

The portion of Imbalance Energy that is not RTD Instructed Imbalance Energy.

* * *

- Variable Energy Resource

A device for the production of electricity that is characterized by an Energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

* * *

Appendix C

Locational Marginal Price

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B. The System Marginal Energy Cost Component of LMP

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

mechanism. A distributed Load Reference Bus will be used for RUC~~, HASP~~ and RTM regardless of whether a distributed Generation Reference Bus were used in the corresponding ~~-~~Integrated Forward Market run. Once the Reference Bus is selected, the System Marginal Energy Cost is the cost of economically providing the next increment of Energy at the distributed Reference Bus, based on submitted Bids.

* * *

Appendix E

Submitted Ancillary Services Data Verification

* * *

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

* * *

Appendix G

Pro Forma Reliability Must-Run Contract

* * *

ARTICLE 1

* * *

DEFINITIONS

* * *

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

* * *

Appendix I Station Power Protocol

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* * *

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

(a) Imports of Net Output must be submitted in Self-Schedules using a Resource ID specified by the CAISO;

(b) ~~HASP Intertie~~FMM Schedules using such Resource ID do not exceed the available Net Output of such generating facilities in any hour;

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

(d) Meter Data for generating facilities located outside the CAISO Balancing Authority Area shall be subject to CAISO audit to verify performance in accordance with these requirements.

* * *

Appendix L Method To Assess Available Transfer Capability

* * *

* * *

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

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

* * *

L.1.3 **Existing Transmission Commitments (ETComm)** include Existing Contracts and Transmission Ownership Rights (TOR). The CAISO reserves transmission capacity for each ETC and TOR based on TRTC Instructions the responsible Participating Transmission Owner or Non-Participating Transmission Owner submits to the CAISO as to the amount of firm transmission capacity that should be reserved on each Transmission Interface for each hour of the Trading Day in accordance with Sections 16 and 17 of the CAISO Tariff. The types of TRTC Instructions the CAISO receives generally fall into three basic categories:

- The ETC or TOR reservation is a fixed percentage of the TTC on a line, which decreases as the TTC is derated (ex. TTC = 300 MW, ETC fixed percentage = 2%, ETC = 6 MWs. TTC derated to 200 MWs, ETC = 4 MWs);

- The ETC or TOR reservation is a fixed amount of capacity, which decreases if the line's TTC is derated below the reservation level (ex. ETC = 80 MWs, TTC declines to 60 MW, ETC = TTC or 60 MWs; or

- The ETC or TOR reservation is determined by an algorithm that changes at various levels of TTC for the line (ex. Intertie TTC = 3,000 MWs, when line is operating greater than 2,000 MWs to full capacity ETC = 400 MWs, when capacity is below 2000 MWs ETC = TTC/2000* ETC).

Existing Contract capacity reservations remain reserved during the Day-Ahead Market and ~~Hour-Ahead Scheduling Process (HASP).~~through the FMM. To the extent that the reservations are unused~~, they~~ after the FMM has been run for a given fifteen-minute interval, then the capacity reservations are released ~~in real-time operations for use in the Real-Time Market~~for the three RTD intervals within that fifteen-minute interval.

Transmissions Ownership Rights capacity reservations remain reserved during the Day-Ahead Market and ~~HASP, as well as through real-time operations.~~Real-Time Market. This capacity is under the control of the Non-Participating Transmission Owner and is not released to the CAISO for use in the markets.

L.1.4 ETC Reservations Calculator (ETCC). The ETCC calculates the amount of firm transmission capacity reserved (in MW) for each ETC or TOR on each Transmission Interface for each hour of the Trading Day.

- **CAISO Updates to ETCC Reservations Table.** The CAISO updates the ETC and TOR reservations table (if required) prior to ~~running the Day-Ahead~~ Market Close of the DAM and ~~HASP~~prior to Market Close of the RTM. The amount of transmission capacity reservation for ETC and TOR rights is determined based on the TTC of each Transmission Interface and in accordance with the curtailment procedures stipulated in the existing agreements and provided to the CAISO by the responsible Participating Transmission Owner or Non-Participating Transmission Owner.

- **Market Notification.** ETC and TOR allocation (MW) information is published for all Scheduling Coordinators which have ETC or TOR scheduling responsibility in advance of the Day-Ahead Market and ~~HASP.~~the Real-Time Market. This information is posted on the Open Access Same-Time Information System (OASIS).

- For further information, see CAISO Operating Procedure M-423, Scheduling of Existing Transmission Contract and Transmission Ownership Rights, which is publicly available on the CAISO Website.

L.1.5 Transmission Reliability Margin (TRM) is an amount of transmission transfer capability reserved at a CAISO Intertie point that is necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

The CAISO uses TRM at Intertie points to account for the following NERC-approved components of uncertainty:

- Forecast uncertainty in transmission system topology, including forced or unplanned outages or maintenance outages.
- Allowances for parallel path (loop flow) impacts, including unscheduled loop flow.

- Allowances for simultaneous path interactions.

The CAISO establishes hourly TRM values for each of the applicable components of uncertainty prior to the Market Close of the ~~HASP~~RTM. The CAISO does not use TRM (i.e., TRM values for Intertie points are set at zero) during the beyond day-ahead and pre-schedule (i.e., planning) time frame identified in R.1.3.3 of NERC Reliability Standard MOD-008-1. A positive TRM value for a given hour is set only if one or more of the conditions set forth below exists for a particular Intertie point. Where none of these conditions exist, the TRM value for a given hour is set at zero.

The methodology the CAISO uses to establish each component of uncertainty is as follows:

The CAISO uses the transmission system topology component of uncertainty to address a potential ATC path limit reduction at an Intertie resulting from an emerging event, such as an approaching wildfire, that is expected to cause a derate of one or more transmission facilities comprising the ATC path. When the CAISO, based on existing circumstances, forecasts that such a derate is expected to occur, the CAISO may establish a TRM value for the affected ATC path in an amount up to, but no greater than, the amount of the expected derate.

The CAISO uses the parallel path component of uncertainty to address the impact of unscheduled flow (USF) over an ATC path that is expected, in the absence of the TRM, to result in curtailment of Intertie Schedules in Real Time as a result of the requirements established in WECC's applicable USF mitigation policies and procedures (WECC USF Policy). When the CAISO forecasts, based on currently observed USF conditions and projected scheduled flow for an upcoming Operating Hour(s), that in the absence of a TRM, scheduled flow will need to be curtailed in Real Time under the applicable WECC USF Policy, the CAISO may establish a TRM for the ATC path for the applicable hour(s) in an amount up to, but no greater than, the forecasted amount that is expected to be curtailed in Real Time pursuant to the WECC USF Policy.

The CAISO uses the simultaneous path interactions component of uncertainty to address the impact that transmission flows on an ATC path located outside the CAISO's Balancing Authority Area may have on the transmission transfer capability of an ATC path located at an Intertie. In the event of such path interactions, the CAISO uses a TRM value to prevent the risk of a system operating limit violation in Real Time for the CAISO ATC path. The amount of the TRM value may be set at a level up to, but not greater than, the forecasted impact on the CAISO ATC path's capacity imposed by expected flow on the non-CAISO ATC path.

The CAISO uses the following databases or information systems, or their successors, in connection with establishing TRM values: SLIC, Existing Transmission Contract Calculator (ETCC), PI, EMS, and CAS.

* * *

L.2 ATC Algorithm

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

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

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

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

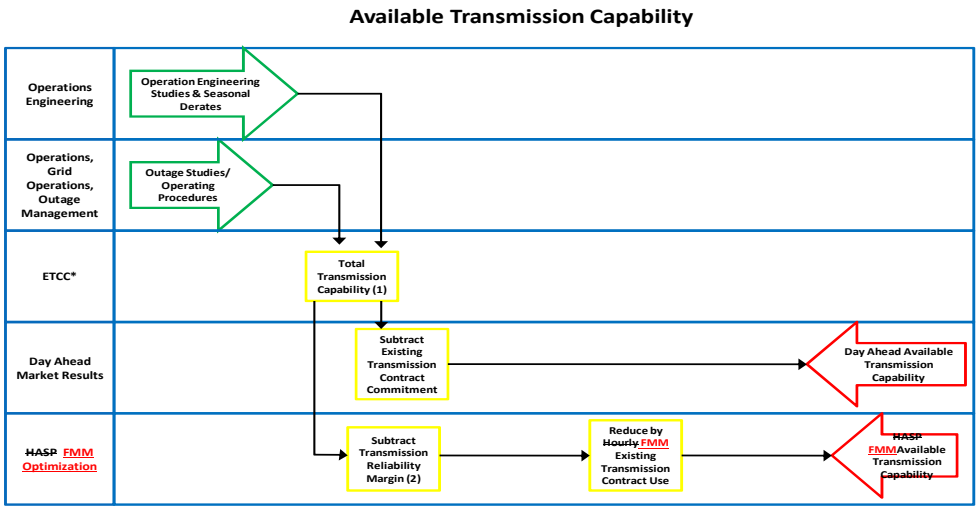
ATC Calculation For Internal Paths 15 and 26:
ATC = TTC – CBM – TRM – Net Energy Flow

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

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

Actual ATC mathematical algorithms and other ATC calculation information are located in the CAISO's ATC Implementation Document (ATCID) posted on OASIS.

L.3 ATC Process Flowchart



*ETCC – Existing Transmission Contract Calculator
(1) – WECC rated path methodology
(2) - See TRMID posted on OASIS

* * *

Appendix M

Dynamic Scheduling Protocol (DSP)

1. DYNAMIC SCHEDULES OF IMPORTS TO THE CAISO BALANCING AUTHORITY AREA

* * *

1.5.8 If there is no Dynamic Schedule in the CAISO's Day-Ahead Market or ~~HASP/~~RTM, the dynamic signal must be at "zero" ("0") except when in response to CAISO's Dispatch Instructions associated with accepted Ancillary Services or Energy Bids.

* * *

1.7.3 All Day-Ahead Market and ~~HASP/~~RTM submitted Dynamic Schedules shall be subject to CAISO Congestion Management and as such may not exceed their transmission reservations in Real-Time (with the exception of intra-hour Dispatch Instructions of the Energy associated with accepted Ancillary Services Bids or Dispatch Instructions for Imbalance Energy).

* * *

* * *

2.5.6 If there is no Dynamic Schedule in the CAISO's Day-Ahead Market or ~~HASP/~~RTM, the dynamic signal must be at "zero" ("0").

* * *

2.6.2 All Day-Ahead Market and ~~HASP/~~RTM submitted Dynamic Schedules shall be subject to CAISO Congestion Management and as such may not exceed their transmission reservations in Real-Time (with the exception of intra-hour Dispatch Instructions for Imbalance Energy issued by the CAISO and responses to the dynamic signal from the Balancing Authority receiving the Dynamic Schedule of the export of Energy).

* * *

Appendix N

Pseudo-Tie Protocol

* * *

1.2.2.3 If there is no Scheduled Generation in the DAM~~, HASP,~~ or Real-Time markets, a Pseudo-Tie Generating Unit shall not generate except when issued an Exceptional Dispatch or operating order as defined in Section 37.2.1.1 of the CAISO Tariff from the CAISO.

* * *

2.2.3.4 In the event of a line outage and a subsequent request by the Balancing Authority for the Attaining Balancing Authority Area for emergency Wheeling service from the CAISO to maintain deliveries of power to the Attaining Balancing Authority Area from the Pseudo-Tie generating unit, all CAISO Tariff market and GMC charges applicable to the resulting use of CAISO transmission service shall be applied for the duration of these events, inclusive of any related ~~HASP~~FMM Schedules.

* * *

Appendix Q

Eligible Intermittent Resources Protocol (EIRP)

* * *

2.2.5 Information Requirements For Participating Intermittent Resource Export Fee

In order for the CAISO to administer, implement and calculate the Participating Intermittent Resource Export Fee, each Participating Intermittent Resource jointly with, and through, its Scheduling Coordinator must provide the CAISO with the following information and documents under the schedule and conditions set forth in this section.

The CAISO will maintain the confidentiality of all information and documents received under this section in accordance with CAISO Tariff Section 20 et seq.

A. A certification, in the form set for in a Business Practice Manual, signed by an officer of the Participating Intermittent Resource and its Scheduling Coordinator, identifying (1) the PIR Export Percentage under Section 5.3.2 of this EIRP for resources that have elected PIRP Protective Measures, if any, and basis thereof, and (2) each contract to sell Energy or capacity from the Participating Intermittent Resource, including for each such contract, the counterparty, start and end dates, delivery point(s), quantity in MW, other temporal terms, i.e., seasonal or hourly limitations.

   The certification must be updated by resubmission to the CAISO (1) upon a request to modify the composition of the Participating Intermittent Resource under Section 2.4.2 of this EIRP; or (2) within ten (10) calendar days of final execution of a new contract or any change in counterparty, start and end dates, delivery point(s), quantity in MW, or other temporal terms, as described above, for any prior certified contract. All other contractual changes will not trigger the obligation for recertification~~;~~.

B. Copies of all contracts, including changes, identified in the above-referenced certification; however, price information may be redacted from the contracts provided.

Each Participating Intermittent Resource, as of November 1, 2006, must initially provide the information requested by this Section 2.2.5 in accordance with a Market Notice provided by the CAISO to Participating Intermittent Resources. All other Eligible Intermittent Resources must satisfy this Section 2.2.5 in order to become a Participating Intermittent Resource after November 1, 2006.

* * *

~~**4.1 Hour-Ahead Forecast**~~

~~The CAISO shall develop expert, independent hourly forecasts of Energy generation for each Participating Intermittent Resource. A forecast shall be published each hour for each of the next seven (7) operating hours. Other forecasts, including a Day-Ahead forecast, may be developed at the CAISO's discretion. The Scheduling Coordinator representing the Participating Intermittent Resource must use the hour-ahead forecast that is available thirty (30) minutes prior to the~~

~~deadline for submitting the HASP/RTM Bids. The CAISO shall use best efforts to provide reliable and timely forecasts. However, if the CAISO fails to deliver the hour-ahead forecast to the Scheduling Coordinator prior to fifteen (15) minutes before the deadline for submitting HASP/RTM Bids, then the hour-ahead forecast shall be the most recent Energy forecast provided by the CAISO to the Scheduling Coordinator for the operating hour for which Bids are next due.~~

* * *

5 SCHEDULING AND SETTLEMENT

5.1 Schedules

For all Generating Units that comprise the Participating Intermittent Resources shall comply with the Bidding and scheduling rules specified in Sections 4.8, 30, 31, and 34. ~~Scheduling Coordinatorsshall be required to submit HASP/RTM Bids (MWh) for the Generating Units that comprise each Participating Intermittent Resource that are identical, in the aggregate, to the hour-ahead forecast published for that Participating Intermittent Resource (MWh).~~

*** * ***

5.3 Participating Intermittent Resource Export Fee

The rules specified in this Section 5.3 and its subsection applies only to Participating Intermittent Resources that have elected PIRP Protective Measures and do not apply to resources that have not elected for such measures.

5.3.3 **Monthly ~~Quarterly~~** Application of Participating Intermittent Resource Export Fee

Each month~~quarter~~ the CAISO will charge Exporting Participating Intermittent Resources the Participating Intermittent Resource Export Fee, as set forth in Schedule 4 of Appendix F.

Attachment C – Matrix of Tariff Revisions

Real-Time Market Design Enhancements Related to Order No. 764

California Independent System Operator Corporation

November 26, 2013

Tariff Sections	Description of Amendment	Rationale for Amendment
4.5.3.12	Delete phrase "HASP Intertie Schedules" because no longer a defined term.	terminology update/conforming change
4.5.3.12	Substitute "AS Awards" and "Virtual Awards" for "awards" and "Virtual Bids," respectively, because new terms provide more precision in language	clarify existing tariff separate from 764 policy changes
4.8.1	Insert rule that resources receiving PIRP Protective Measures cannot submit Economic Bids.	implement new treatment of VERs
4.8.2	Establishes that all Scheduling Coordinators for EIRs must provide meteorological data and are subject to the forecast fee.	implement new treatment of VERs
4.8.2.1.1	EIRs may use their own forecast if certified to do so, but ability to do so may be terminated under certain circumstances.	implement new treatment of VERs
4.8.2.1.2	EIRs may use the ISO forecast.	implement new treatment of VERs
4.8.2.2	Forecast fee applies irrespective of whether the EIR uses its own resource or the ISO forecast.	implement new treatment of VERs
4.8.3.1.1	Resources seeking PIRP protective measures must complete their election within 30 days of effective date of new tariff provisions.	implement new treatment of VERs
4.8.3.1.2	Resources seeking PIRP protective measures must submit affidavits to qualify.	implement new treatment of VERs
4.8.3.1.2.1	Statement of what affidavit is required for resources qualifying for PIRP protective measures based on physical limitations.	implement new treatment of VERs
4.8.3.1.2.2	Statement of what affidavit is required for resources qualifying for PIRP protective measures based on contractual limitations.	implement new treatment of VERs
4.8.3.2	Resources seeking PIRP Protective Measures must meet certain requirements.	implement new treatment of VERs
4.8.3.2.1	One requirement to receive PIRP Protective Measures relates to the resource's exposure to Real-Time Imbalance Energy.	implement new treatment of VERs
4.8.3.2.2	Another requirement to receive PIRP Protective Measures relates to the resource's ability to curtail its output.	implement new treatment of VERs
4.8.3.2.2.1	The limitation on curtailment can be physical.	implement new treatment of VERs
4.8.3.2.2.2	The limitation on curtailment can be contractual.	implement new treatment of VERs
4.8.3.3	PIRP Protective Measures expire at the earlier of three years or when a new/amended contract addresses the settlement of Imbalance Energy	implement new treatment of VERs
4.8.3.4	The ISO will post on its website the resources that will receive PIRP Protective Measures.	implement new treatment of VERs
4.9.5.2	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
6.5.4	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
6.5.4	RTM bid submission does not open until DAM results are posted so if DAM posting is off schedule, then RTM bid submission will be delayed accordingly	clarify existing tariff separate from 764 policy changes
6.5.4.1.1	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
6.5.4.1.2	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
6.5.4.1.5	HASP results will publish at 45 minutes before the Trading Hour.	terminology update/conforming change
6.5.4.1.6	Deleted because all aspects of HASP publication now governed by one deadline.	terminology update/conforming change
6.5.4.2.1	Under new market design "HASP Schedules" is not a precise term.	terminology update/conforming change
6.5.4.2.2	Delete phrase "HASP Intertie Schedules" because no longer a defined term.	terminology update/conforming change
6.5.4.2.2	Under new market design there are no more HASP Intertie LMPs.	terminology update/conforming change
6.5.5	Amend section title with the phrase "During the Trading Hour" recognizes that the RTM covers time before and during the Trading Hour.	terminology update/conforming change
6.5.5.2.2	LMPs for the FMM also need to be posted every 15 minutes	terminology update/conforming change
7.6.1	Substitute "FMM" for "HASP."	terminology update/conforming change
7.7.1	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
7.7.3.2	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
7.7.11.4.2	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
7.7.14.2.2	Substitute "FMM Schedules" for "HASP Intertie Schedules."	terminology update/conforming change
7.7.15.2.2	Under new market design the advisory RTUC run is now a binding FMM market run	terminology update/conforming change
7.7.15.2.3	Delete reference to HASP because it is now explicitly defined as a RTM market process.	clarify existing tariff separate from 764 policy changes
8.1	No longer necessary to distinguish between HASP and RTM under new market design.	terminology update/conforming change
8.2.3.1	Under new market design the advisory RTUC run is now a binding FMM market run.	terminology update/conforming change
8.3.1	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
8.3.1	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
8.3.1	Ancillary Services are now procured through HASP and FMM so in some instances it is more accurate to refer generally to RTM and sometimes more accurate to refer specfically to FMM.	terminology update/conforming change
8.3.2	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
8.3.3.2	Spell out the abbreviation "DA" to clarify that "DA Schedules" means "Day-Ahead Schedules."	clarify existing tariff separate from 764 policy changes
8.3.3.2	"HASP Intertie Schedules" no longer a defined term	terminology update/conforming change
8.3.3.3	Substitute "Real-Time Market" for "HASP" and "RTUC" because HASP is part of RTM as is RTUC and FMM.	terminology update/conforming change
8.3.5	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
8.3.7	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
8.4.1.2	Substitute "FMM" for "RTUC."	terminology update/conforming change

Tariff Sections	Description of Amendment	Rationale for Amendment
8.6.1	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
8.6.1	The deleted sentence repeats information already covered in Appendix A of the tariff. The ISO finds it is better practice to try to consolidate definitional language in Appendix A.	clarify existing tariff separate from 764 policy changes
8.6.2	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
8.6.4.2	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
8.7	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
8.7	Due to new market structure, different information will be released on CMRI on a different timetable.	terminology update/conforming change
8.10.8.7	Substitute "Real-Time Market" for "HASP" and "RTUC."	terminology update/conforming change
9.3.6.4	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
9.3.6.11	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
9.3.10.2	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
11.1(e)	Substitute "FMM Schedule" for "HASP Intertie Schedule."	terminology update/conforming change
11.1(e)	State that there is specific FMM ASMP for settlement.	terminology update/conforming change
11.1.2	ISO did not believe it was necessary to list the specific charge/payment types in this introductory section	clarify existing tariff separate from 764 policy changes
11.2.4.4.1	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
11.2.4.4.1	Remove obsolete references to Converted Rights.	clarify existing tariff separate from 764 policy changes
11.2.4.6	CRR clawback for convergence bidding rewritten for clarity but no substantive change.	clarify existing tariff separate from 764 policy changes
11.2.4.6(a)	Substitute "RTM" for "HASP" and "RTD."	terminology update/conforming change
11.3.1	Under new market design the FMM LMP is most closely analogous to the "Dispatch Interval Real-Time LMPs" for purposes of settling convergence bids.	terminology update/conforming change
11.3.2	Under new market design the FMM LMP is most closely analogous to the "Dispatch Interval Real-Time LMPs" for purposes of settling convergence bids.	terminology update/conforming change
11.4	Section removed because there is no more distinct HASP settlement.	substantive change implementing new design
11.4.1	Section removed because there is no more distinct HASP settlement.	substantive change implementing new design
11.4.2	Section removed because there is no more distinct HASP settlement.	substantive change implementing new design
11.5	Amendments create distinction between imbalance energy in FMM and in RTD. Further distinction created between Instructed and Uninstructed Imbalance Energy for RTD (RTD IIE & RTD UIE, respectively). There is no opportunity to have uninstructed deviations in FMM so there is no need for FMM UIE as a term.	substantive change implementing new design
11.5.1.1	Amendments describe the forms of FMM IIE.	substantive change implementing new design
11.5.1.2	Amendments describe the forms of RTD IIE.	substantive change implementing new design
11.5.2	Removes the notion of Tier 1 and Tier 2 UIE.	substantive change implementing new design
11.5.2.2	Describes that demand in RTM is settled at both Default LAPs and Custom LAPs based on a weighted average price combining the four FMM and 12 RTD LMPs.	substantive change implementing new design
11.5.2.3	Substitute "Real-Time Dispatch for "Real-Time Market."	terminology update/conforming change
11.5.3	Updates statement of the price at which Unaccounted For Energy will be settled.	substantive change implementing new design
11.5.4.1	Delete section because concept of Dispatch Interval LMPs no longer applies.	terminology update/conforming change
11.5.4.2	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
11.5.5	Under new market design it is important to clarify that when Residual Imbalance Energy is reclassified as Derate Energy it is settled at the RTD LMP.	substantive change implementing new design
11.5.6	Under new market design it is necessary to distinguish between FMM and RTD IIE.	terminology update/conforming change
11.5.6.1	Under new market design it is necessary to distinguish between FMM and RTD IIE.	terminology update/conforming change
11.5.6.1.1	Under new market design it is necessary to distinguish between FMM and RTD IIE.	terminology update/conforming change
11.5.6.2	Under new market design it is necessary to distinguish between FMM and RTD IIE.	terminology update/conforming change
11.5.6.2.3	Under new market design it is necessary to distinguish between FMM and RTD IIE.	terminology update/conforming change
11.5.6.2.4	Under new market design it is necessary to distinguish between FMM and RTD IIE.	terminology update/conforming change
11.5.6.4	Under new market design it is necessary to distinguish between FMM and RTD IIE.	terminology update/conforming change
11.5.6.6	Under new market design it is necessary to distinguish between FMM and RTD IIE.	terminology update/conforming change
11.5.6.7.1	Under new market design it is necessary to distinguish between FMM and RTD IIE.	terminology update/conforming change
11.5.6.7.3	Under new market design it is necessary to distinguish between FMM and RTD IIE.	terminology update/conforming change
11.5.7.1	Updating description of how the congestion credit for ETCs and TORs is calculated to ensure that congestion charges are not settled against balanced ETCs/TORs	substantive change implementing new design
11.5.7.2	Updating description of how the cost of losses credit for ETCs and TORs is calculated to ensure that transmission loss charges are not settled against balanced ETCs/TORs.	substantive change implementing new design
11.5.8.1	Substitute "FMM and RTD LMPs" for "Dispatch Interval LMPs."	terminology update/conforming change
11.8	Clarifies that RTM Energy Bid Costs and Market Revenues include Bid Costs from the FMM.	substantive change implementing new design

Tariff Sections	Description of Amendment	Rationale for Amendment
11.8.1	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
11.8.1.3	Correcting typographical error.	clarify existing tariff separate from 764 policy changes
11.8.4	Clarifies that RTM Energy Bid Costs and Market Revenues include Bid Costs from the FMM.	substantive change implementing new design
11.8.4.1.4	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
11.8.4.2.1	Clarify that the Real-Time Market includes both FMM and RTD LMPs.	terminology update/conforming change
11.8.4.2.2	Clarify that the Real-Time Market includes both FMM and RTD LMPs.	terminology update/conforming change
11.8.4.2.2	Delete superceded reference to "HASP Self Scheduled Energy."	terminology update/conforming change
11.8.6.6	Substitute "FMM" for "HASP."	terminology update/conforming change
11.8.6.6	Update term "HASP Intertie Schedules" to new defined term "HASP Block Intertie Schedules."	terminology update/conforming change
11.9.1	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
11.9.1	Under new design, Inter-SC Trades in RTM will be settled at simple average of the four FMM LMPs.	substantive change implementing new design
11.9.2	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
11.10.1.2	Ancillary Services provided from HASP Block Intertie Schedules are paid the simple average of the four FMM ASMPs rather than the HASP ASMPs (which are no longer the basis of settlement).	substantive change implementing new design
11.10.1.2	Substitute "FMM" for "HASP."	terminology update/conforming change
11.10.1.2.1	Substitute "FMM" for "HASP."	terminology update/conforming change
11.10.2	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
11.10.4.1	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
11.10.9	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
11.12.1	Description of how PIRP Protective Measures are settled.	implement new treatment of VERs
11.12.1.1	For PIRP Protective Measures, resources will first be settled as all other resources.	implement new treatment of VERs
11.12.1.2	At end of each month, resources receiving PIRP Protective Measures will receive a resettlement amount.	implement new treatment of VERs
11.12.1.3	Resources receiving PIRP Protective Measures can also receive unique treatment regardin Inter-SC trades if certain requirements are met.	implement new treatment of VERs
11.12.2	Describes how the costs of PIRP Protective Measures will be allocated.	implement new treatment of VERs
11.12.3.3	PIRP Export Fee applies to resources receiving PIRP Protective Measures.	implement new treatment of VERs
11.12.4	Deleting obsolete provision regarding settlement of Uninstructed Deviations for Participating Intermittent Resources.	terminology update/conforming change
11.17.1.2.1	Update persistent deviation metric to account for changed timeline of Settlement Intervals.	terminology update/conforming change
11.17.1.2.2	Update persistent deviation metric to account for changed timeline of Settlement Intervals.	terminology update/conforming change
11.17.1.2.2	Clarify that the Real-Time Market includes both FMM and RTD LMPs.	terminology update/conforming change
11.21.1	Substitute "FMM" for "HASP." Substitute "FMM Schedule" for "HASP Intertie Schedule."	terminology update/conforming change
11.25.1	Substitute "FMM" for "RTUC."	terminology update/conforming change
11.25.1	The Real-Time System Marginal Energy Cost used in calculating compensation for resolving the Flexible Ramping Constraint will now be the FMM interval rather than the average of the five-minute dispatch intervals.	substantive change implementing new design
11.25.2	Removes the notion of Tier 1 and Tier 2 UIE.	substantive change implementing new design
11.29.5.3	Substitute "Real-Time Market" for "Hour-Ahead Market."	terminology update/conforming change
11.29.5.3	Existing language contains typographical error in referring to the Hour-Ahead Market.	clarify existing tariff separate from 764 policy changes
11.29.17.2.1	Substitute "FMM" for "HASP."	terminology update/conforming change
11.31	Updating the "Decline Potential Charge" to operate under the new market design.	substantive change implementing new design
11.31.1	Updating the "Decline Potential Charge" to operate under the new market design.	substantive change implementing new design
11.31.2	Updating the "Decline Potential Charge" to operate under the new market design.	substantive change implementing new design
11.32	Updating the "HASP Reversal Rule" to apply where the schedule is reversed through the FMM.	substantive change implementing new design
11.33	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
16.4.5	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
16.5	Substitute "Real-Time Market" for "HASP." Delete reference to "HASP Bids."	terminology update/conforming change
16.5.1	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
16.9.1	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
16.9.1	Incorporating language that was previously cross-referenced to Section 33.3 because Section is being deleted in its entirety.	substantive change implementing new design
16.11	Substitute "FMM" for "HASP."	terminology update/conforming change
17.1.4	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
17.2	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
17.2.1	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
17.4.1	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change

Tariff Sections	Description of Amendment	Rationale for Amendment
17.6	Substitute "FMM" for "HASP."	terminology update/conforming change
27	Amending high-level description of CAISO Markets to reflect what ISO will now do in the Real-Time Market timeframe.	substantive change implementing new design
27.1.1	Deleting description of HASP LMPs and inserting explanation of FMM LMPs.	substantive change implementing new design
27.1.2.1	Updating description of what market processes award Ancillary Services.	substantive change implementing new design
27.1.2.2	Substitute "FMM" for "RTUC."	terminology update/conforming change
27.1.2.2	Updating description of what Ancillary Services schedules have a $0 opportunity cost.	terminology update/conforming change
27.2.2.2	Deleting obsolete language describing calculation of Hourly Real-Time LAP Prices and providing cross-reference to Section 11.5.2.2, which includes the updated description.	terminology update/conforming change
27.2.2.2.1	Clarifying that there is a distinct FMM and RTD LMP for a Default LAP and that the price is what is produced from the respective optimization runs.	terminology update/conforming change
27.2.2.2.2	Clarifying that there is a distinct FMM and RTD LMP for a Custom LAP and that the price is what is produced from the respective optimization runs	terminology update/conforming change
27.4.1	Substitute "FMM" for "RTUC."	terminology update/conforming change
27.4.1	Updating description of what the SCUC performs in HASP.	substantive change implementing new design
27.4.3.1	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
27.4.3.1	Delete reference to Section 34.10.	terminology update/conforming change
27.4.3.1	Substitute "RTM" for "Real-Time Dispatch."	terminology update/conforming change
27.4.3.1	Remove phrase "or less" from description of price at which market software relaxes Transmission Constraints in the RTM because existing language was in error.	clarify existing tariff separate from 764 policy changes
27.5.1.1	Substitute "FMM Schedule" for "HASP Intertie Schedule."	terminology update/conforming change
27.5.2	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
27.5.6	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
27.7.3	Substitute "RTM" for "HASP, STUC or RTUC."	terminology update/conforming change
27.7.5	Update cross-reference.	terminology update/conforming change
27.9	Substitute "FMM" for "RTUC."	terminology update/conforming change
27.10.	Substitute "RTM" for "HASP, RTUC, STUC and RTED."	terminology update/conforming change
27.10.	Substitute "FMM" for "RTUC."	terminology update/conforming change
28.1.2	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
28.1.2	Change settlement of Inter-SC Trade in RTM to settle on the simple average of four FMM LMPs.	substantive change implementing new design
28.1.3	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
28.1.3	Change settlement of Inter-SC Trade in RTM to settle on the simple average of four FMM LMPs.	substantive change implementing new design
28.1.5	Substitute "FMM" for "RTM."	terminology update/conforming change
28.1.6	Substitute "FMM Schedule" for "HASP Advisory Schedule."	terminology update/conforming change
28.1.6.2	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
28.1.6.3	Substitute "FMM Schedule" for "HASP Advisory Schedule."	terminology update/conforming change
28.2.2	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
28.2.3	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
28.3.2	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
28.3.3	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
30.1.2	Address perceived confusion in this provision as to whether "Bids" includes "Self-Schedules."	clarify existing tariff separate from 764 policy changes
30.1.2	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
30.1.2	Clarify what it means for a Bid to be rejected.	clarify existing tariff separate from 764 policy changes
30.2	Add parenthetical to make clear that Self-Schedules are not permitted in all cases (e.g., for convergence bidding).	clarify existing tariff separate from 764 policy changes
30.5.1(a)	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
30.5.1(a)	Clarify that Scheduling Coordinators submit one bid set to be used for all RTM processes.	terminology update/conforming change
30.5.1(b)	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
30.5.1(f)	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
30.5.1(q)	Description of bidding rules for Self-Schedule Hourly Block bid type.	substantive change implementing new design
30.5.1(r)	Description of bidding rules for Variable Energy Resource Self-Schedule bid type.	substantive change implementing new design
30.5.1(s)	Description of bidding rules for Economic Hourly Block Bids bid type.	substantive change implementing new design
30.5.1(t)	Description of bidding rules for Economic Hourly Block Bids with Intra-Hour Option bid type.	substantive change implementing new design
30.5.1(u)	Clarification that Scheduling Coordinators can submit regular Economic Bids or Self-Schedules.	substantive change implementing new design
30.5.1(u)	The new bid types described are optional.	substantive change implementing new design

Tariff Sections	Description of Amendment	Rationale for Amendment
30.5.2.1	Create cross-reference to new e-Tagging rules in Section 30.6.2.	terminology update/conforming change
30.5.2.4	Delete superceded statement regarding Non-Dynamic Resource-Specific System Resources.	terminology update/conforming change
30.5.2.5	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
30.5.2.6	Delete superceded statement regarding Non-Dynamic Resource-Specific System Resources.	terminology update/conforming change
30.5.2.6	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
30.5.2.6	Update terminology for type of schedules that create hourly Ancillary Services awards.	terminology update/conforming change
30.5.4	Clarify scope of Wheeling Through transactions to include Economic Bids or Self-Schedules.	terminology update/conforming change
30.5.4	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
30.6.2	New e-Tagging rules to account for potential intra-hour schedule changes in new market design.	substantive change implementing new design
30.6.2.1	New e-Tagging rules to account for potential intra-hour schedule changes in new market design.	substantive change implementing new design
30.6.2.2	New e-Tagging rules to account for potential intra-hour schedule changes in new market design.	substantive change implementing new design
30.6.2.3	New e-Tagging rules to account for potential intra-hour schedule changes in new market design.	substantive change implementing new design
30.6.2.4	New e-Tagging rules to account for potential intra-hour schedule changes in new market design.	substantive change implementing new design
30.6.2.5	New e-Tagging rules to account for potential intra-hour schedule changes in new market design.	substantive change implementing new design
30.7.1	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
30.7.3.6.3	Update for Convergence Bidding position limits to account for reinstatement of such bidding at Interties.	substantive change implementing new design
30.7.3.6.3.2	Statement of phase-in schedule of Intertie Convergence Bidding.	substantive change implementing new design
30.7.4	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
30.7.6.1	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
30.7.6.1	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
30.7.6.2	Substitute "FMM" for "RTUC."	terminology update/conforming change
30.8	Include Virtual Bids in scope of Bids that cannot be submitted on open Interties.	terminology update/conforming change
30.8	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
30.9	Amend description of Virtual Bidding to account for reinstatement of such bidding at Interties.	substantive change implementing new design
31.8	Statement of what constraints are enforced in which market processes to account for reinstatement of Virtual Bidding at Interties.	substantive change implementing new design
31.3.1.1	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
31.5.3	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
31.5.3.5	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
31.6.3	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
31.8	Defining the dual constraint used to account for Intertie Convergence Bidding.	substantive change implementing new design
33	Section 33, which covers the HASP, is being deleted in its entirety -- tariff provisions relevant in new market design is incorporated elsewhere in the tariff.	terminology update/conforming change
33.1	Section 33, which covers the HASP, is being deleted in its entirety -- tariff provisions relevant in new market design is incorporated elsewhere in the tariff.	terminology update/conforming change
33.2	Section 33, which covers the HASP, is being deleted in its entirety -- tariff provisions relevant in new market design is incorporated elsewhere in the tariff.	terminology update/conforming change
33.3	Section 33, which covers the HASP, is being deleted in its entirety -- tariff provisions relevant in new market design is incorporated elsewhere in the tariff.	terminology update/conforming change
33.4	Section 33, which covers the HASP, is being deleted in its entirety -- tariff provisions relevant in new market design is incorporated elsewhere in the tariff.	terminology update/conforming change
33.5	Section 33, which covers the HASP, is being deleted in its entirety -- tariff provisions relevant in new market design is incorporated elsewhere in the tariff.	terminology update/conforming change
33.6	Section 33, which covers the HASP, is being deleted in its entirety -- tariff provisions relevant in new market design is incorporated elsewhere in the tariff.	terminology update/conforming change
33.7	Section 33, which covers the HASP, is being deleted in its entirety -- tariff provisions relevant in new market design is incorporated elsewhere in the tariff.	terminology update/conforming change
33.8	Section 33, which covers the HASP, is being deleted in its entirety -- tariff provisions relevant in new market design is incorporated elsewhere in the tariff.	terminology update/conforming change
33.9	Section 33, which covers the HASP, is being deleted in its entirety -- tariff provisions relevant in new market design is incorporated elsewhere in the tariff.	terminology update/conforming change
34	Update of introductory portion of RTM markets section to reflect new market design accurately.	substantive change implementing new design
34.1	Statement that there are inputs to the Real-Time Market.	substantive change implementing new design
34.1.1	Explain that Day-Ahead Market results are an input to the Real-Time Market.	substantive change implementing new design
34.1.1	Day-Ahead transactions are not deemed performed until Real-Time.	substantive change implementing new design
34.1.2	Statement of market model used in Real-Time Market.	substantive change implementing new design

Tariff Sections	Description of Amendment	Rationale for Amendment
34.1.3	Statement of rules and timeline on submitting Bids to the RTM.	substantive change implementing new design
34.1.1	Day-Ahead results are an input to the market for Real-Time.	substantive change implementing new design
34.1.2	The ISO uses the same base market model in RTM as in IFM, with a few adjustments.	substantive change implementing new design
34.1.3	Bid sumission timeline for the RTM.	substantive change implementing new design
34.1.4	Statement of Bid validation rules in the RTM.	substantive change implementing new design
34.1.5	Statement of market power mitigation applied to Bids used in the Real-Time Market processes.	substantive change implementing new design
34.1.6.1	Statement of how ISO uses forecasts from EIRs that elect to use their own forecast.	implement new treatment of VERs
34.1.6.2	Statement of how ISO uses forecasts from EIRs that elect to use the ISO forecast.	implement new treatment of VERs
34.1.6.3	Statement of how ISO uses forecasts from resources utilizing PIRP Protective Measures.	implement new treatment of VERs
34.2.1	Statement of how HASP optimization functions, including use of SCUC optimization, particular Base Market Models, and what demand it clears against.	substantive change implementing new design
34.2.2	Statement of how the various types of Self-Schedules are treated in HASP.	substantive change implementing new design
34.2.3	Statement of treatment of Ancillary Services procured through HASP and FMM.	substantive change implementing new design
34.2.4	HASP results are published by 45 minutes before Trading Hour.	substantive change implementing new design
34.2.5	If HASP processes cannot be performed, then ISO can abort HASP and perform remaining RTM market processes.	substantive change implementing new design
34.3.1	Description of the RTUC Optimization under new market design.	substantive change implementing new design
34.3.2 (34.2.1)	Renumbering existing sections to account for new material -- was 34.2.1.	terminology update/conforming change
34.4	Statement of new Fifteen Minute Market.	substantive change implementing new design
34.4.1 (34.2.2)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.5 (34.3)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.5	Description of how RTD operates under new market design.	substantive change implementing new design
34.5.1 (34.3.1)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.5.1	Explanation of how VERs with five-minute forecast granularity are optimized through RTED.	substantive change implementing new design
34.5.2.1 (34.3.2.1)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.5.2.2 (34.3.2.2)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.5.3 (34.3.3)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.6 (34.4)	Updating operation of STUC under new market design.	substantive change implementing new design
34.7 (34.5)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.8 (34.6)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.9 (39.7)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.10. (34.8)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.11 (34.9)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.11.1 (34.9.1)	Update to conditions under which ISO can issue Exceptional Dispatch related to System Emergencies.	substantive change implementing new design
34.11.2 (34.9.2)	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
34.11.2	Renumbering existing sections to account for new material.	terminology update/conforming change
34.11.3 (34.9.3)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.11.4 (34.9.4)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.12 (34.10)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.12.1 (34.10.1)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.12.2 (34.10.2)	Substitute "Self-Schedule Hourly Block" for "HASP Self-Schedule."	terminology update/conforming change
34.13 (34.11)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.13.1 (34.11.1)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.13.2 (34.12.2)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.14 (34.12)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.15 (34.13)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.16.1 (34.14.1)	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
34.16.2 (34.14.2)	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
34.17 (34.15)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.17.1 (34.15.1)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.17.1(c) (34.15.1)	Substitute "FMM" for "HASP."	terminology update/conforming change
34.17.1(f) (34.15.1)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.17.1(g) (34.15.1)	Update terminology to reflect "HASP Block Intertie Schedules."	terminology update/conforming change
34.17.2 (34.15.2)	Renumbering existing sections to account for new material.	terminology update/conforming change

Tariff Sections	Description of Amendment	Rationale for Amendment
34.17.2(a) (34.15.2)	Substitute "FMM" for "RTUC."	terminology update/conforming change
34.17.2(b) (34.15.2)	Substitute "FMM" for "RTUC."	terminology update/conforming change
34.17.2(c) (34.15.2)	Substitute "FMM" for "RTUC."	terminology update/conforming change
34.17.3 (34.15.3)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.17.4 (34.15.4)	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
34.17.5 (34.15.5)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.17.6 (34.16.6)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.18 (34.16)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.18.1 (34.16.1)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.18.2 (34.16.2)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.18.3 (34.16.3)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.18.3.1 (34.16.3.1)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.18.3.2 (34.16.3.2)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.18.3.3 (34.16.3.3)	Clarify that Bids are submitted to RTM for HASP rather than submitted to HASP.	terminology update/conforming change
34.18.3.4 (34.16.1)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.19 (34.17)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.19.1 (34.17.1)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.19.2 (34.17.2)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.19.3 (34.17.3)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.19.4 (34.17.4)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.19.5 (34.17.5)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.20. (34.8)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.20. (34.19)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.20.1 (34.19.1)	Substitute "FMM or RTD LMP" for "Resource-Specific Settlement Interval LMP."	terminology update/conforming change
34.20.2 (34.19.2)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.20.2.1 (34.19.2.1)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.20.2.2 (34.19.2.2)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.20.2.3 (34.19.2.3)	Renumbering existing sections to account for new material.	terminology update/conforming change
34.21.1	Criteria for a temporary waiver of timing requirements in the RTM.	substantive change implementing new design
34.21.2	What must be published on CMRI where there is a timing waiver.	substantive change implementing new design
35.1	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
37.3.1.1	Update language to conform cross-reference to the HASP reversal.	terminology update/conforming change
39.7	Update to cross-references regarding market power mitigation procedures.	terminology update/conforming change
39.7.2.1	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
39.7.2.2	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
39.7.2.2(b)(iii)	Substitute "FMM" for "HASP."	terminology update/conforming change
39.7.2.2(b)(iii)	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
39.7.2.2(b)(vi)	Substitute "FMM" for "HASP."	terminology update/conforming change
39.7.2.2(b)(vi)	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
39.7.3	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
39.7.3.4	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
39.10.3(iv)	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
40.5.1(2)	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
40.5.1(2)	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
40.5.4(2)	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
40.6.4.3.2	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
40.6.5	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
40.6.7	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
40.6.8.1.2	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
40.6.11	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
41.5.1	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
41.5.3	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change

Tariff Sections	Description of Amendment	Rationale for Amendment
Alert, Warning or Emergency (AWE) Notice	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
Ancillary Service Award Or AS Award	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
Ancillary Service Schedule or AS Schedule	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
Bid Cost Recovery (BCR) Eligible Resources	Create rule that Self-Schedule Hourly Blocks and Economic Hourly Block Bids (with or without Intra-Hour Option) are not BCR Eligibile Resources.	substantive change implementing new design
CAISO Markets	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
CAISO Markets Processes	Add references to HASP and FMM.	terminology update/conforming change
Commitment Interval	Substitute "FMM" for "RTUC."	terminology update/conforming change
Decline Monthly Charge – Exports	Insert "Block" to conform terminology to new market design.	terminology update/conforming change
Decline Monthly Charge – Imports	Insert "Block" to conform terminology to new market design.	terminology update/conforming change
Decline Potential Charge – Exports	Insert "Block" to conform terminology to new market design.	terminology update/conforming change
Decline Potential Charge – Imports	Insert "Block" to conform terminology to new market design.	terminology update/conforming change
Decline Threshold Percentage – Imports/Exports	Insert "Block" to conform terminology to new market design.	terminology update/conforming change
Decline Threshold Quantity – Imports/Exports	Insert "Block" to conform terminology to new market design.	terminology update/conforming change
Derate Energy	Delete superceded term.	terminology update/conforming change
Eligible Intermittent Resource	Redefine Eligible Intermittent Resources as a subset of Variable Energy Resources.	substantive change implementing new design
Exceptional Dispatch	Substitute "FMM or RTD LMP" for "Dispatch Interval LMP."	terminology update/conforming change
Exceptional Dispatch Energy	Delete superceded term.	terminology update/conforming change
Expected Energy	Substitute "FMM or RTD LMP" for "Real-Time LMP."	terminology update/conforming change
Expected Energy	Substitute "FMM Schedules" for "HASP Intertie Schedules."	terminology update/conforming change
Fast Start Unit	Substitute "FMM" for "RTUC."	terminology update/conforming change
Fifteen Minute Market (FMM)	Add new definition.	substantive change implementing new design
FMM AS Award	Add new definition.	substantive change implementing new design
FMM Derate Energy	Add new definition.	substantive change implementing new design
FMM Exceptional Dispatch Energy	Add new definition.	substantive change implementing new design
FMM IE Settlement Amount	Add new definition.	substantive change implementing new design
FMM Instructed Imbalance Energy (FMM IIE)	Add new definition.	substantive change implementing new design
FMM Minimum Load Energy	Add new definition.	substantive change implementing new design
FMM MSS Price	Add new definition.	substantive change implementing new design
FMM Non-Overlapping Optimal Energy	Add new definition.	substantive change implementing new design
FMM Optimal Energy	Add new definition.	substantive change implementing new design
FMM Overlapping Optimal Energy	Add new definition.	substantive change implementing new design
FMM Schedule	Add new definition.	substantive change implementing new design
Forced Outage	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
HASP Advisory Schedule	Clarify that the term is defined with respect to schedules from HASP that are not HASP Block Intertie Schedules..	substantive change implementing new design
HASP Bid	Delete superceded term.	terminology update/conforming change
HASP Block Intertie Schedule	Define term as a HASP schedule with binding quantity resulting from accepted Self-Schedule Hourly Blocks and awarded Economic Hourly Block.	substantive change implementing new design
HASP Intertie LMP	Delete superceded term.	terminology update/conforming change
Hour-Ahead Scheduling Process (HASP)	Define term with cross-reference to Section 34.2.	substantive change implementing new design
HASP Inter-SC Trade Period	Delete superceded term.	terminology update/conforming change
Imbalance Energy	Delete superceded term.	terminology update/conforming change
Instructed Imbalance Energy	Delete superceded term.	terminology update/conforming change
Market Clearing	Update term to reflect new types of Schedules under new market design.	terminology update/conforming change
Market Close	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
Market Power Mitigation – RRD	Substitute "Real-Time Market" for "HASP."	terminology update/conforming change
MSS Load Following Energy	Clarify that basis of MSS settlement largely is related to RTD prices rather than FMM.	substantive change implementing new design

Tariff Sections	Description of Amendment	Rationale for Amendment
Net Procurement	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
Non-Overlapping Optimal Energy	Delete superceded term.	terminology update/conforming change
Non-priced Quantity	Substitute "FMM" for "HASP."	terminology update/conforming change
Non-Spinning Reserve Cost	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
Operational Adjustment	Updates term to refer to the FMM Schedule rather than Dispatch Interval IIE.	substantive change implementing new design
Optimal Energy	Delete superceded term.	terminology update/conforming change
Overlapping Optimal Energy	Delete superceded term.	terminology update/conforming change
Persistent Deviation Metric	Updates term to reflect that Settlement Interval is now five minutes so that two hours consists of 24 intervals.	terminology update/conforming change
PIRP Protective Measures	Add new definition.	substantive change implementing new design
Real-Time Congestion Offset	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
Real-Time Market (RTM)	Redefine term to include HASP specifically and also FMM.	substantive change implementing new design
Real-Time Market Pumping Bid Cost	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
Real-Time Self-Scheduled Energy	Delete superceded term.	terminology update/conforming change
Real-Time Unit Commitment (RTUC)	Delete superceded term.	terminology update/conforming change
Real-Time Minimum Load Energy	Delete superceded term.	terminology update/conforming change
Real-Time Pumping Energy	Delete superceded term.	terminology update/conforming change
Real-Time Settlement Interval MSS Price	Delete superceded term.	terminology update/conforming change
Resource-Specific Settlement Interval LMP	Delete superceded term.	terminology update/conforming change
RTD Derate Energy	Add new definition.	substantive change implementing new design
RTD Exceptional Dispatch Eenrgy	Add new definition.	substantive change implementing new design
RTD IIE Settlement Amount	Add new definition.	substantive change implementing new design
RTD Imbalance Energy	Add new definition.	substantive change implementing new design
RTD Instructed Imbalance Energy (RTD IIE)	Add new definition.	substantive change implementing new design
RTD Minimum Load Energy	Add new definition.	substantive change implementing new design
RTD MSS Price	Add new definition.	substantive change implementing new design
RTD Non-Overlapping Optimal Energy	Add new definition.	substantive change implementing new design
RTD Optimal Energy	Add new definition.	substantive change implementing new design
RTD Overlapping Optimal Energy	Add new definition.	substantive change implementing new design
RTD Pumping Energy	Add new definition.	substantive change implementing new design
RTM Congestion Credit	Add new definition.	substantive change implementing new design
RTM Inter-SC Trade Period	Add new definition.	substantive change implementing new design
RTM MCL Credit For Eligible TOR Self-Schedules	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
RTUC	Update definition.	terminology update/conforming change
Schedule	Redefine term to include either Day-Ahead or FMM Schedules.	substantive change implementing new design
Security Constrained Unit Commitment (SCUC)	Update definition to include Hourly Intertie Block Schedules and FMM Schedules.	substantive change implementing new design
Self-Provided Ancillary Services	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
Self-Schedule	Clarify that the term includes Variable Energy Resource Self-Schedules.	terminology update/conforming change
Set Point	Substitute "FMM" for "HASP."	terminology update/conforming change
Settlement Interval	Clarify that the interval is five minutes.	substantive change implementing new design
Spinning Reserve Cost	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
Tier 1 UIE	Delete superceded term.	terminology update/conforming change
Tier 2 UIE	Delete superceded term.	terminology update/conforming change
Tolerance Band	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
Uninstructed Imbalance Energy	Clarify that UIE is defined with respect to RTD IIE, rather than FMM IIE.	substantive change implementing new design
Variable Energy Resource	Add new definition.	substantive change implementing new design
Appendix C – B.	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
Appendix E – 6.	Substitute "FMM" for "HASP."	terminology update/conforming change
Appendix G – Forced Outage	Substitute "RTM" for "HASP."	terminology update/conforming change

Tariff Sections	Description of Amendment	Rationale for Amendment
Appendix I – 1.2.3(b)	Substitute "FMM Schedules" for "HASP Intertie Schedules."	terminology update/conforming change
Appendix L – L.1.1	Clarifying/clean-up change related to FERC Docket No. ER12-1468 -- parenthetical in question inadvertently was not deleted in that filing.	clarify existing tariff separate from 764 policy changes
Appendix L – L.1.3	Update language concerning transmission reservations to reflect new market design.	substantive change implementing new design
Appendix L – L.1.4	Update language concerning transmission reservations to reflect new market design.	substantive change implementing new design
Appendix L – L.1.5	Substitute "RTM" for "HASP."	terminology update/conforming change
Appendix L – L.2	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
Appendix L – L.2	Clarify existing language through use of defined term "Market Close."	clarify existing tariff separate from 764 policy changes
Appendix L – L.3	Substitute "FMM" for "HASP."	terminology update/conforming change
Appendix M – 1.5.8	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
Appendix M – 1.7.3	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
Appendix M – 2.5.6	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
Appendix M – 2.6.2	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
Appendix N – 1.2.2.3	Delete reference to HASP because it is now explicitly defined as a RTM market process.	terminology update/conforming change
Appendix N – 2.2.3.4	Substitute "FMM" for "HASP."	terminology update/conforming change
Appendix Q – 2.2.5	The PIR Export Percentage now applies to resources receiving PIRP Protective Measures.	implement new treatment of VERs
Appendix Q – 4.1	Provision regarding Hour-Ahead forecast no longer needed.	implement new treatment of VERs
Appendix Q – 5.1	Requirement to comply with PIRP bidding rules.	implement new treatment of VERs
Appendix Q – 5.3	The PIRP Export fee applies,	implement new treatment of VERs
Appendix Q – 5.3.3	The export fee applies on a monthly basis.	implement new treatment of VERs

Substantive Change Implementing New Design

11.4	31.8	FMM Optimal Energy
11.4.1	34	FMM Overlapping Optimal
11.4.2	34.1	Energy
11.5	34.1.1	FMM Schedule
11.5.1.1	34.1.1	HASP Advisory Schedule
11.5.1.2	34.1.2	HASP Block Intertie
11.5.2	34.1.3	Schedule
11.5.2.2	34.1.1	Hour-Ahead Scheduling
11.5.3	34.1.2	Process (HASP)
11.5.5	34.1.3	MSS Load Following
11.5.7.1	34.1.4	Energy
11.5.7.2	34.1.5	Operational Adjustment
11.8	34.2.1	PIRP Protective Measures
11.8.4	34.2.2	Real-Time Market (RTM)
11.9.1	34.2.3	RTD Derate Energy
11.10.1.2	34.2.4	RTD Exceptional Dispatch
11.25.1	34.2.5	Eenrgy
11.25.2	34.3.1	RTD IIE Settlement
11.31	34.4	Amount
11.31.1	34.5	RTD Imbalance Energy
11.31.2	34.5.1	RTD Instructed Imbalance
11.32	34.6 (34.4)	Energy (RTD IIE)
16.9.1	34.11.1 (34.9.1)	RTD Minimum Load
27	34.21.1	Energy
27.1.1	34.21.2	RTD MSS Price
27.1.2.1	Bid Cost Recovery (BCR)	RTD Non-Overlapping
27.4.1	Eligible Resources	Optimal Energy
28.1.2	Eligible Intermittent	RTD Optimal Energy
28.1.3	Resource	RTD Overlapping Optimal
30.5.1(q)	Fifteen Minute Market	Energy
30.5.1(r)	(FMM)	RTD Pumping Energy
30.5.1(s)	FMM AS Award	RTM Congestion Credit
30.5.1(t)	FMM Derate Energy	RTM Inter-SC Trade Period
30.5.1(u)	FMM Exceptional Dispatch	Schedule
30.5.1(u)	Energy	Security Constrained Unit
30.6.2	FMM IE Settlement	Commitment (SCUC)
30.6.2.1	Amount	Settlement Interval
30.6.2.2	FMM Instructed	Uninstructed Imbalance
30.6.2.3	Imbalance Energy (FMM	Energy
30.6.2.4	IIE)	Variable Energy Resource
30.6.2.5	FMM Minimum Load	Appendix L – L.1.3
30.7.3.6.3	Energy	Appendix L – L.1.4
30.7.3.6.3.2	FMM MSS Price	
30.9	FMM Non-Overlapping	
31.8	Optimal Energy	

* Some sections may be listed under multiple categories

Implement New Treatment of VERs

4.8.1
4.8.2
4.8.2.1.1
4.8.2.1.2
4.8.2.2
4.8.3.1.1
4.8.3.1.2
4.8.3.1.2.1
4.8.3.1.2.2
4.8.3.2
4.8.3.2.1
4.8.3.2.2
4.8.3.2.2.1
4.8.3.2.2.2
4.8.3.3
4.8.3.4
11.12.1
11.12.1.1
11.12.1.2
11.12.1.3
11.12.2
11.12.3.3
34.1.6.1
34.1.6.2
34.1.6.3
Appendix Q – 2.2.5
Appendix Q – 4.1
Appendix Q – 5.1
Appendix Q – 5.3
Appendix Q – 5.3.3

* Some sections may be listed under multiple categories

Terminology Updates and Conforming Changes

4.5.3.12
4.9.5.2
6.5.4
6.5.4.1.1
6.5.4.1.2
6.5.4.1.5
6.5.4.1.6
6.5.4.2.1
6.5.4.2.2
6.5.4.2.2
6.5.5
6.5.5.2.2
7.6.1
7.7.1
7.7.3.2
7.7.11.4.2
7.7.14.2.2
7.7.15.2.2
8.1
8.2.3.1
8.3.1
8.3.1
8.3.1
8.3.2
8.3.3.2
8.3.3.3
8.3.5
8.3.7
8.4.1.2
8.6.1
8.6.2
8.6.4.2
8.7
8.7
8.10.8.7
9.3.6.4
9.3.6.11
9.3.10.2
11.1(e)
11.1(e)
11.2.4.4.1
11.2.4.6(a)
11.3.1
11.3.2
11.5.2.3
11.5.4.1
11.5.4.2
11.5.6
11.5.6.1
11.5.6.1.1
11.5.6.2
11.5.6.2.3
11.5.6.2.4
11.5.6.4
11.5.6.6
11.5.6.7.1
11.5.6.7.3
11.5.8.1
11.8.1
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31.5.3
31.5.3.5

* Some sections may be listed under multiple categories

Terminology Updates and Conforming Changes

31.6.3	34.17.4 (34.15.4)	Alert, Warning or
33	34.17.5 (34.15.5)	Emergency (AWE) Notice
33.1	34.17.6 (34.16.6)	Ancillary Service Award Or
33.2	34.18 (34.16)	AS Award
33.3	34.18.1 (34.16.1)	Ancillary Service Schedule
33.4	34.18.2 (34.16.2)	or AS Schedule
33.5	34.18.3 (34.16.3)	CAISO Markets
33.6	34.18.3.1 (34.16.3.1)	CAISO Markets Processes
33.7	34.18.3.2 (34.16.3.2)	Commitment Interval
33.8	34.18.3.3 (34.16.3.3)	Decline Monthly Charge –
33.9	34.18.3.4 (34.16.1)	Exports
34.3.2 (34.2.1)	34.19 (34.17)	Decline Monthly Charge –
34.4.1 (34.2.2)	34.19.1 (34.17.1)	Imports
34.5 (34.3)	34.19.2 (34.17.2)	Decline Potential Charge –
34.5.1 (34.3.1)	34.19.3 (34.17.3)	Exports
34.5.2.1 (34.3.2.1)	34.19.4 (34.17.4)	Decline Potential Charge –
34.5.2.2 (34.3.2.2)	34.19.5 (34.17.5)	Imports
34.5.3 (34.3.3)	34.20. (34.8)	Decline Threshold
34.7 (34.5)	34.20. (34.19)	Percentage –
34.8 (34.6)	34.20.1 (34.19.1)	Imports/Exports
34.9 (39.7)	34.20.2 (34.19.2)	Decline Threshold
34.10. (34.8)	34.20.2.1 (34.19.2.1)	Quantity –
34.11 (34.9)	34.20.2.2 (34.19.2.2)	Imports/Exports
34.11.2 (34.9.2)	34.20.2.3 (34.19.2.3)	Derate Energy
34.11.2	35.1	Exceptional Dispatch
34.11.3 (34.9.3)	37.3.1.1	Exceptional Dispatch
34.11.4 (34.9.4)	39.7	Energy
34.12 (34.10)	39.7.2.1	Expected Energy
34.12.1 (34.10.1)	39.7.2.2	Expected Energy
34.12.2 (34.10.2)	39.7.2.2(b)(iii)	Fast Start Unit
34.13 (34.11)	39.7.2.2(b)(iii)	Forced Outage
34.13.1 (34.11.1)	39.7.2.2(b)(vi)	HASP Bid
34.13.2 (34.12.2)	39.7.2.2(b)(vi)	HASP Intertie LMP
34.14 (34.12)	39.7.3	HASP Inter-SC Trade
34.15 (34.13)	39.7.3.4	Period
34.16.1 (34.14.1)	39.10.3(iv)	Imbalance Energy
34.16.2 (34.14.2)	40.5.1(2)	Instructed Imbalance
34.17 (34.15)	40.5.1(2)	Energy
34.17.1 (34.15.1)	40.5.4(2)	Market Clearing
34.17.1(c) (34.15.1)	40.6.4.3.2	Market Close
34.17.1(f) (34.15.1)	40.6.5	Market Power Mitigation
34.17.1(g) (34.15.1)	40.6.7	– RRD
34.17.2 (34.15.2)	40.6.8.1.2	Net Procurement
34.17.2(a) (34.15.2)	40.6.11	Non-Overlapping Optimal
34.17.2(b) (34.15.2)	41.5.1	Energy
34.17.2(c) (34.15.2)	41.5.3	Non-priced Quantity
34.17.3 (34.15.3)		

* Some sections may be listed under multiple categories

Terminology Updates and Conforming Changes

Non-Spinning Reserve Cost
Optimal Energy
Overlapping Optimal Energy
Persistent Deviation Metric
Real-Time Congestion Offset
Real-Time Market Pumping Bid Cost
Real-Time Self-Scheduled Energy
Real-Time Unit Commitment (RTUC)
Real-Time Minimum Load Energy
Real-Time Pumping Energy
Real-Time Settlement Interval MSS Price
Resource-Specific Settlement Interval LMP
RTM MCL Credit For Eligible TOR Self-Schedules
RTUC
Self-Provided Ancillary Services
Self-Schedule
Set Point
Spinning Reserve Cost
Tier 1 UIE
Tier 2 UIE
Tolerance Band
Appendix C – B.
Appendix E – 6.
Appendix G – Forced Outage
Appendix I – 1.2.3(b)
Appendix L – L.1.5
Appendix L – L.2
Appendix L – L.3
Appendix M – 1.5.8
Appendix M – 1.7.3
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Appendix M – 2.6.2
Appendix N – 1.2.2.3
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Clarification of Existing Tariff Language Unrelated to Order 764 Policy Changes

4.5.3.12
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Appendix L – L.1.1
Appendix L – L.2

* Some sections may be listed under multiple categories

Attachment D – April 24, 2013 Addendum to Draft Final Proposal

Real-Time Market Design Enhancements Related to Order No. 764

California Independent System Operator Corporation

November 26, 2013

FERC Order 764 Compliance
15-Minute Scheduling and Settlement

Addendum to Draft Final Proposal

April 24, 2013

15-Minute Scheduling and Settlement
Addendum to Draft Final Proposal
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1 Introduction

On June 22, 2012, FERC approved Order 764[1] to remove barriers to the integration of variable energy resources by requiring each transmission provider to: (1) offer an option to schedule energy with 15-minute granularity; and, (2) require variable energy resources to provide meteorological and forced outage data for the purpose of power production forecasting. For the California ISO (ISO), the primary changes required by the 15-minute scheduling option required under the FERC order are to intertie transactions since internal resources are dispatched every five minutes. The ISO is required to make a compliance filing with FERC by November 12, 2013 to describe how it proposes to address these items.

In this draft final proposal, the ISO is seeking to maximize the use of existing market functionality to meet the FERC compliance obligation and address real-time market inefficiencies while minimizing potential seams issues with neighboring balancing authorities. The ISO proposes to introduce a 15-minute financially binding settlement within the real-time market that will apply to both intertie and internal resources as well as load. Currently, the ISO real-time market includes a fifteen minute process for real-time unit commitment (RTUC) and procurement of incremental ancillary services. The hour-ahead scheduling process (HASP), in the existing market, is a special run of the real-time unit commitment run which results in financially binding hourly energy and ancillary services schedules for non-dynamic intertie transactions. Under the proposed 15-minute market, energy and ancillary services schedules for internal generation, and dynamic and non-dynamic intertie transactions will be financially binding every fifteen minutes. Load will also settle in this 15-minute market based on deviations from day-ahead energy schedules and ISO forecast. The ISO is not proposing any changes to the existing five minute real-time dispatch (RTD).

FERC Order 764 only requires that transmission providers offer resources an *option* to update energy schedules every fifteen minutes. It does not require a transmission provider to require 15-minute energy scheduling for interties, neither does it address internal resource scheduling. However, it does provide a transmission provider the option to propose a superior approach.

Consequently, the ISO believes that Order 764 is an opportunity to implement real-time market changes that were not possible before the order. As described in more detail below, the ISO's proposal for adding full 15-minute energy scheduling and settlement is a superior option because:

- It complies with the Order 764 to allow for 15-minute energy scheduling at the interties. At the same time, it the proposal includes provisions to allow for hourly schedules of intertie transactions to remain. However, the ISO would no longer guarantee the price of those schedules for the entire hour.

- It addresses existing real-time imbalance energy offset issues that occur because of changes between the HASP and RTD optimizations. Under the ISO's proposed design, the same market optimization will produce settlement prices for both internal and external resources.

[1] Additional information is available at www.ferc.gov on the Commission's order in Docket No. RM10-11-000; Order No. 764 Integration of Variable Energy Resources

- It addresses previous convergence bidding issues at the interties, which resulted from virtual bids for interties settling at the HASP locational marginal price (LMP) and internal nodes settling at the RTD LMP. The proposal includes the reinstatement of convergence bidding at the interties.

- It meets the needs of variable energy resources through the ability to provide more frequent energy schedules using forecast updates closer to the financially binding interval.

The ISO believes that many external parties will take advantage of 15-minute energy scheduling. However, over the next few years, transmission reservations within WECC will likely remain predominantly hourly. There is also no indication at this time that NAESB, NERC or FERC will modify the e-tag deadlines within the compliance timeline of the order. Under its proposed real-time market design, the ISO would no longer award hourly, financially binding energy schedules in the real-time market for intertie transactions. Instead, the ISO would clear and settle intertie energy schedules on a fifteen minute basis. In order to align with the twenty minute e-tag submission deadline prior to energy flow, the ISO will align the market timeline for the 15-minute market such that the market results are consistent with WECC tagging practices. If WECC moves to 15-minute transmission reservations and shorter e-tag timelines in the future, the ISO can further enhance the real-time market design to run the 15-minute market closer to actual flow.

Order No. 764 does not require that the ISO settle intertie transactions on a fifteen minute basis. But, the Commission recognizes that transmission providers may wish to adopt additional market redesigns that provide better flexibility than the minimal requirements in the order.[2] In the past two years, the ISO has identified a number of inefficiencies with its current hour-ahead scheduling processes and real-time market settlement. Introducing the financial settlement of the 15-minute market addresses these market inefficiencies. In its recent stakeholder efforts, the ISO and participants determined a root cause of the market inefficiencies under the current market design. They observed that intertie transactions are financially binding based on HASP LMPs, however, load and internal generation are financially binding based on RTD LMPs. The HASP and RTD optimizations run at different time delays and with different market interval durations. As a result, system conditions are not aligned when running these applications which results in price divergence and market uplifts.

By aligning to a single, 15-minute financially binding real-time optimization, most of the current real-time market pricing issues are addressed. This enables the reintroduction of convergence bidding on the interties. Prior to suspension, convergence bids for interties were priced in real-time at the HASP LMP and internal nodes were priced at RTD LMPs. Convergence bids settled in different market optimizations negatively impacted the market efficiency of virtual bids. The alignment of the real-time settlement addresses these issues. While not the driver of suspending convergence bidding on the interties, the other issue that must be addressed in order for convergence bidding to be reinstated on the interties is prices inconsistent with bids as a result of the enforcing both the physical and physical + virtual constraints in the day-ahead market.

[2] *See* Order No. 764 PP 99, 107.

2 Plan for Stakeholder Engagement

Item	Date
Post Addendum to Draft Final Proposal	April 24, 2013
Stakeholder Conference Call	May 1, 2013
Board Meeting	May 15/16, 2013
Tariff Filing	November 2013

3 Changes to Draft Final Proposal

- Convergence bidding position limit for the first twelve months will be zero percent and then follow the scheduled increases as previously proposed.

- Establish a process to identify existing PIRP resources where operational characteristics may require additional protective measures for the energy settlement provisions under the FERC Order No. 764 market design changes.

4 Renewable Integration: Market Vision and Roadmap

During the Renewable Integration: Market and Product Review Phase II initiative, the ISO discussed with stakeholders a potential redesign of the real-time market to a 15-minute dispatch and a new balancing product to manage changes between the dispatch and regulation. During the stakeholder process it was concluded that it would be unlikely that in the next two to three years 15-minute schedules within WECC would not be realized. Also, the implementation complexity of the 15-minute dispatch design would not be achievable in two to three years due to significant software changes required for implementing the new balancing product. As a result, the ISO developed seven guiding principles to assess the comparative value and merits of the market enhancements proposed near, mid, and long term market enhancements. The ISO briefed the Board of Governors in December 2011 on these guiding principles. FERC Order 764 significantly shortened the assumed timing for the implementation of 15 minute scheduling in WECC. In considering options to allow 15 minute scheduling, the ISO sought to be consistent with the guiding principles in this proposal.

The seven guiding principles are:

Technology Agnostic

Principle	The ISO market accommodates new resource types based on their performance capabilities, without preference for specific technologies.
Expected Outcomes	✓ Enables any technically capable resource, regardless of technology, to provide services on a level playing field based on performance ✓ Resource technologies are viable based on innovation and competition rather than on resource-specific market rules ✓ Integrates devices that can both produce and consume energy

Transparent

Principle	The ISO market relies on price signals to incent participant behaviors that align with ISO operating needs.
Expected Outcomes	✓ Products are competitively procured through transparent market mechanisms ✓ Procurement targets are transparent and tied to operational needs ✓ Operating constraints are reflected in price signals, minimizing non-market solutions ✓ Prices incent performance from supply and demand that supports operational needs and encourages mitigation of generation variability and congestion ✓ Pricing rules allow transparent allocation of renewable integration costs

Deep and Liquid

Principle	The ISO market attracts robust resource participation.
Expected Outcomes	✓ More economic bids and less self-scheduling ✓ More price responsive demand ✓ Increased participation from resources in other balancing authorities through improved interchange scheduling ✓ Minimal seams issues with neighboring balancing authorities

Durable and Sustainable

Principle	The ISO market ensures an efficient mix of resources to maintain reliability and attracts new investment when and where needed.
Expected Outcomes	✓ Resources are commercially viable through a combination of ISO market revenues and forward contracts ✓ Resource fleet and mix enables the ISO to meet NERC and WECC reliability standards ✓ Resources are incented to enhance availability and performance ✓ Market products and rules are stable ✓ Known real-time market issues are addressed

Flexible and Scalable

Principle	The ISO market easily adapts to new and changing energy policy goals and resource mix.
Expected Outcomes	✓ Establish flexible market design that can accommodate reasonable changes in policies and technologies ✓ Recognize key linkages and coordinate with initiatives and proceedings of state agencies ✓ Compatible with high penetration levels of distributed energy resources

Cost-effective and Implementable

Principle	The ISO market design leverages existing ISO infrastructure, industry experiences and lessons learned.
Expected Outcomes	✓ A market design that is cost-effective to implement for market participants and the ISO ✓ Build on existing functionality and market systems to extent possible ✓ Design leverages the experience of other ISOs/RTOs as to what works and what does not; do not re-invent

Cost Causation

Principle	The ISO market allocates costs based on cost causation
Expected Outcomes	✓ Market participants better manage their load and resource variability ✓ More accurate forecasting and scheduling by market participants reduces operational uncertainty and associated costs

5 Real-Time Market Timeline

The current real-time market is composed of three processes:

- The HASP establishes hourly financially binding energy and ancillary services for intertie transactions.
- The RTUC establishes financially binding ancillary services awards and unit commitment for internal generation.
- The RTD then establishes financially binding energy dispatches for internal generation. The RTD optimization is based on demand (including losses) calculated by the ISO's state estimator, and load is settled based upon the actual metered demand.

The ISO proposes to replace the HASP with an hourly process to accept block schedules on the interties. The 15-minute market run will dispatch other intertie transactions. To address the

need to support hourly intertie energy schedules, in the straw proposal, the ISO proposed leveraging the market functionality gained from the Dynamic Transfers initiative to award financially binding hourly transmission reservations for dynamic intertie transactions.

Based upon further discussion with stakeholders, the ISO is no longer proposing to implement transmission reservations bidding and settlement. The Dynamic Transfer initiative assumed that all static intertie energy schedules would be hourly. The transmission reservation established a process to ensure that dynamically scheduled variable energy resources could (1) secure sufficient hourly transmission capacity to meet positive forecast errors and (2) establish a cost of securing hourly transmission capacity in excess of its expected energy to incentivize improved forecasting.

Under the FERC Order 764 paradigm, the two objectives above can be met by a market design that creates incentives for static intertie schedules to be able to be economically reduced if variable energy imports schedule greater import quantities in the 15-minute market than they would have reserved if required to commit to energy delivery for the entire hour. As a result, it is no longer necessary to implement transmission reservations to support dynamic transfers.

The proposed real-time market timeline has been designed to limit seams issues with neighboring balancing authorities by remaining consistent with the existing e-tagging and intra-interval ramping practices in the West. The proposal maintains existing market timelines wherever possible to minimize the impact on the business processes of market participants and neighboring balancing authorities.

5.1 Real-Time Bid Submission

The ISO proposes to retain hourly submission of bids to the real-time market. These bids will be used to:

- Economically accept hourly block schedules
- Economically schedule resources for energy in the 15-minute market
- Economically dispatch resources in the 5-minute real-time market runs

The bid submission timeline has the same deadline under the current real-time market design. The same economic bids will be used in both the 15-minute market and RTD. There will be no changes to the hourly bid information provided by internal generation. As is currently the case, load will clear based on ISO forecasted demand by DLAP. Therefore, load serving entities will not be allowed to bid their load in the real-time market.

Variable energy resources that plan to use their forecast unless the price is below certain amount can use an economic bid curve[3] to indicate the willingness to forgo the forecast schedule. If the economic bid curve is submitted, the forecast schedule will essentially be used as a cap on the economic bid curve for both the 15-minute market and RTD. This will allow the 15-minute and RTD to clear accordingly. This will provide the ISO with a mechanism to

[3] As part of the flexible ramping product design, variable energy resources can submit additional information so that they can be awarded flexible ramping down and can be decremented from their 15-minute self-schedules. The ability to submit a decremental bid to a variable energy resource's self-schedule will be implemented with the FERC Order 764 market design changes, which is before the implementation of the flexible ramping product.

economically curtail variable energy resources below their forecasted output, which will provide significant reliability benefits in over-generation conditions. To get this functionality in as soon as possible, the proposal includes implementing this functionality in the fall of 2013 for hourly variable energy resource self-schedules until the 15 minute market is implemented in the spring of 2014. This is further described in section 7.4 below.

FERC Order 764 does not require changes from hourly transmission reservations to 15-minute transmission reservations – it only addresses *energy* schedules, as opposed to *transmission* scheduling. In addition, the ISO proposes not to require intertie resources to provide 15-minute energy schedule updates.

The ISO believes, over time, the hourly timeline, as illustrated in Figure 1, could be pulled in closer to the start of the hour though additional automation of intertie scheduling checkout business processes. However, it is important to note that the hourly block schedules must be accepted at or before the market optimization starts for the first binding 15-minute market in a trade hour. As shown in Figure 1 below, hourly block schedules are accepted forty-five minutes before the hour. As is explained below, this is 7.5 minutes prior to the start of the optimization for the first 15-minute market in the trade hour.

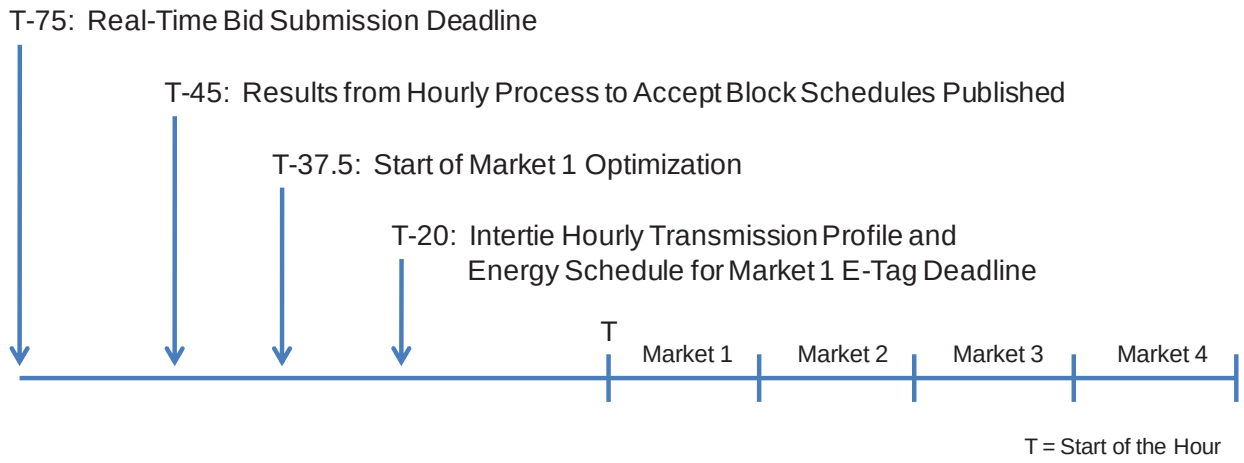

Figure 1 - Timeline of Hourly Real-Time Processes

The bids submitted by intertie resources will change somewhat under the ISO's proposal to accommodate both hourly and 15-minute economic bids and self-schedules. The ISO will run separate processes for accepting hourly block schedules and determining binding energy schedules and ancillary services awards. Intertie resources will submit the following information:

1. Energy self-schedule and/or energy bid, same as currently
2. Ancillary services bids, same as currently
3. Flag to require bid to be considered as an hourly block schedule
4. Flag to allow a single curtailment for the remainder of the hour for accepted block schedules

5. Flag to determine participation in the 15-minute market if the intertie transaction is not accepted in the hourly process

5.2 Hourly Process to Accept Block Schedules

Under the proposed 15-minute market design, there no longer will be financially binding HASP schedules for energy and ancillary services over the interties. Using the existing RTUC market functionality, the ISO will determine financially binding energy and ancillary services schedules within each 15-minute interval. The ISO will determine these simultaneously for each 15-minute interval based on energy self-schedules and energy and ancillary services bids. As illustrated in figure 1 above, for each trading hourly there will be four 15-minute markets.

The ISO will also run a market optimization to accept hourly block schedules and provide advisory energy schedules and ancillary services awards. The results will be published at T-45 which is the same time as current HASP schedules are provided and will be used for tagging hourly transmission profiles.

The proposal includes several options for intertie resources to manage any transitional seams issues as the WECC moves to 15-minute energy scheduling. The following six scheduling options will be available for intertie transactions:

1. Self-scheduled hourly block
2. Self-scheduled variable energy resource forecast
3. Economic bid hourly block
4. Economic bid hourly block with single intra-hour schedule change
5. Economic bid with participation in 15-minute market
6. Dynamic Transfer

In the hourly process to accept block schedules, the market optimization will enforce a constraint that each 15-minute interval, the energy schedule of submitted hourly block schedules will be equal. Then in the financially binding 15-minute market, the accepted hourly block schedule will be considered a self-schedule. For self-scheduled variable energy resource forecast, the market optimization will use the forecasted energy for each 15-minute interval, thus there is not restriction that the expected energy is flat for the hour. Then in the financially binding 15-minute interval the variable energy resource can update its self-schedule based on the most current forecast which will be used in the 15-minute market.

For economic bids submitted in the 15-minute market and dynamic transfers, the market optimization will produce advisory energy schedules for each 15-minute interval. The energy schedule in the financially binding 15-minute market can be different than the advisory schedule that cleared the hourly process to accept block schedules. However, the 15-minute energy schedule cannot exceed the transmission capacity listed on e-tag prior to the start of the binding 15-minute market optimization.

Ancillary services can also be awarded as a block schedule and will be considered self-provision in the 15-minute market to determine the financially binding ancillary services price. Currently, if the ISO dispatches contingency reserves on the interties the energy schedule remains at the dispatched level for the remainder of the hour. The implementation of the 15-minute market will not change this WECC practice. For example, assume a resource has an hourly block advisory energy schedule of 100 MW and a spinning reserve schedule of 50 MW. In the event that the spinning reserve was dispatched in interval 2, the energy schedule would increase to 150MW, the remaining intervals of the hour, including 15-minute and 5-minute markets, will reflect a self-schedule of energy at 150 MW.

Figure 2 below illustrates the outcome of the hourly process to accept block schedules. In this example, the intertie has an import limit of 1,000 MW. The sum of economic bids which would clear if not limited by transmission capacity would be 800 MW in interval 1, 900 MW in interval 2, 1,000 MW in interval 3 and 1,100 MW in interval 4. Since the sum of economic bids which would clear is greater than the import limit, the full sum of economics bids which would clear cannot be awarded in interval 4. The hourly blocks and hourly blocks with intra-hour schedule change clear at the same MW quantity for each 15-minute interval – 300 MW for hourly blocks and 200 MW for hourly blocks with intra-hour schedule change. The variable energy resource's hourly forecast is 100 MW for interval 1, 200 MW for interval 2, 300 MW for interval 3 and 400 MW for interval 4. The economic bids that will participate in the 15-minute market and Dynamic Transfers clear at 200 MW for the first three intervals, but at 100 MW for the fourth interval since the import limit has been reached. Figure 2 also shows variable energy resources can exceed their forecasted energy up to the MW quantity of economic bids participating in the 15-minute market and the amount of Dynamic Transfers since those advisory schedules can be curtailed economically in the binding 15-minute market.

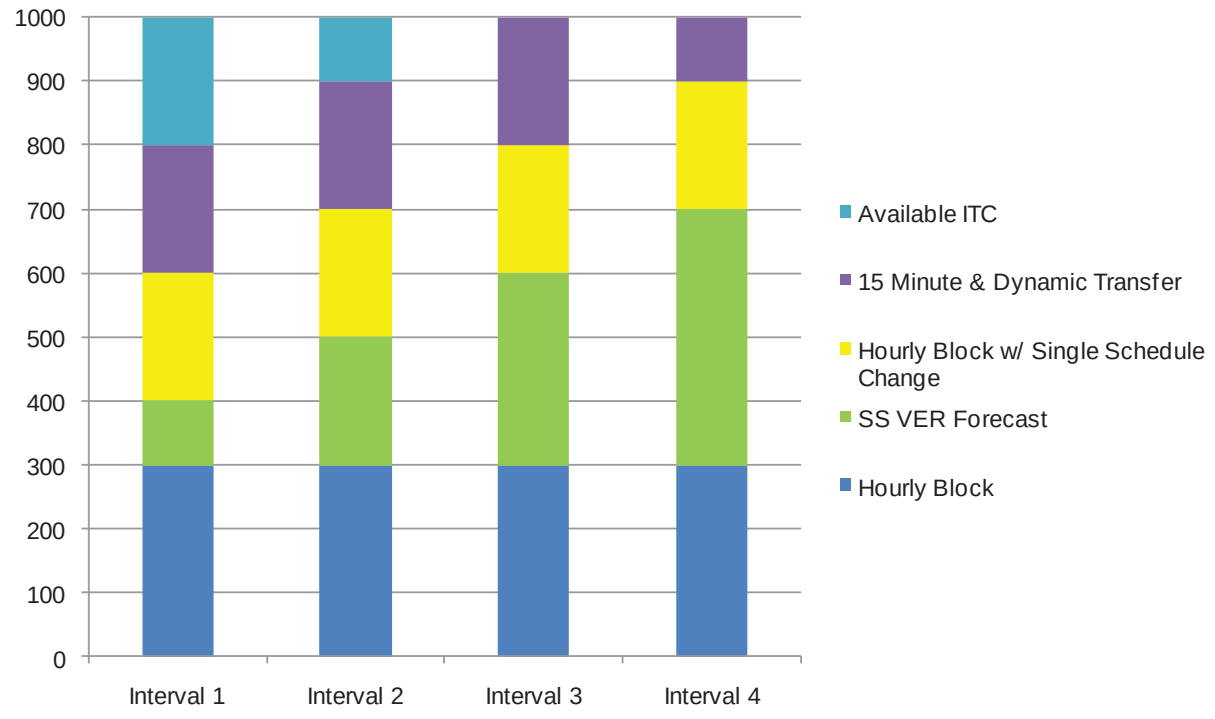

Figure 2 - Example of hourly process to accept block schedules

The following outlines the e-tags the ISO would approve by the hourly tagging deadline for each of the intertie bidding options above. As shown, the ISO would approve e-tags with transmission profiles that exceed the maximum projected 15-minute energy or hourly block award (if submitted with single intra-hour change). This is so the ISO can dispatch these intertie resources with these e-tags in the 15-minute market above their projected 15-minute energy or hourly block award. This may result in the ISO accepting tags with transmission profiles that in aggregate exceed the transfer capacity of an intertie, but in no case will the ISO accept e-tags that have energy profiles and ancillary services awards that in aggregate exceed the transfer capacity of an intertie.

E-tags would be submitted as follows:

1. Self-scheduled hourly block

    T-20 (before the hour) Tag

        Transmission profile = hour ahead process schedule

        Energy profile = hour ahead process schedule

    No changes to tag made from 15-minute market

    Energy profile can be updated intra-hour due to reliability curtailments

2. Self-scheduled variable energy resource forecast

    At T-75, use 15-minute granular forecast for hour-ahead process

    At T-37.5, updated forecast used for self-schedule in first 15-minute market

    T-20 (before the hour) tag,

        Transmission profile >= maximum projected energy award in15-minute intervals from hour-ahead process

        Energy profile = 15-minute market schedule for interval 1

    Energy profile updated every 15 minutes

3. Economic bid hourly block

    T-20 (before the hour) Tag

        Transmission profile = hour ahead process schedule

        Energy profile = hour ahead process schedule

    No changes to tag made from 15-minute market

    Energy profile can be updated intra-hour due to reliability curtailments

4. Economic bid hourly block with single intra-hour schedule change

    T-20 (before the hour) Tag

        Transmission profile >= hour ahead process energy schedule

Energy profile = hour ahead process schedule unless updated in first 15-minute market

15-minute market can increment energy profile up to lowest transmission profile tagged prior to start of binding 15-minute market optimization.

15-minute market can decrement.

Energy profile updated once within the hour 20 minutes prior to flow and remains unchanged for balance of hour.

5. Economic bid with participation in 15-minute market

T-20 (before the hour) Tag

Transmission profile >= maximum MW energy bid submitted for participation in 15-minute market

Energy profile = 15-minute market schedule for interval 1

Energy profile is updated every 15 minutes based upon 15-minute market results

6. Dynamic Transfer

T-20 (before the hour) Tag

Transmission profile >= maximum MW bid submitted

Final energy profile in dynamic tag will be updated after schedule hour

5.2.1 Self-Scheduled Variable Energy Resource Forecast

Variable energy resources can use the ISO forecast for their 15-minute expected energy in the hourly process to accept block schedules. In addition, a variable energy resource can also use its own forecast of expected energy; however, if the expected energy is not delivered in the 15-minute market, the variable energy resource will be subject to a penalty similar to the existing HASP schedules decline charge, as discussed in more detail in a section 6.2 below. This ensures that variable energy resources using their own forecast do not overstate expected energy that crowds out hourly block schedules. Since the advisory energy schedule that clears from the hourly process to accept block schedules is not financially binding this penalty mechanism is used to incentivize forecasting actual expected energy. The hourly block process schedules declines charge also applies to other intertie transactions that do not e-tag an accepted hourly block schedule which is advisory.

5.2.2 Economic Bid Hourly Block with Single Intra-Hour Schedule Change

In order to increase the amount of energy schedules that can change in the 15-minute process, the ISO proposes to allow hourly block schedules the option of being economically dispatched once in the hour. Given the proliferation of intermittent resources, the ISO believes entities throughout the WECC region will take advantage of 15-minute energy scheduling. However, over the next few years, transmission reservations within WECC will remain predominantly hourly. Currently WECC allows and has established business processes that support a single intra-hour schedule change of intertie schedules. While the WECC provisions are for

reliability, rather than economic curtailments, it is reasonable to expect the associated business processes could be relatively easily adapted to accommodate economic curtailments.

The proposed single intra-hour schedule change of intertie schedules will work as follows for a curtailment:

- Assume an hourly block import has bid of $50.00. In the hourly process to accept block schedules, the import is accepted for 100 MW.
- In interval 1 of the 15-minute market the LMP is $55.00 and the import is economic for the remainder of the hour, the import flows and is paid $55.00.
- Then in interval 2, the 15-minute market the LMP drops to $45.00 and the import is not economic for the remainder of the hour, the import is curtailed and does not flow in interval 2, interval 3, and interval 4.
- If in interval 3 and interval 4, the price increased to $55.00, the import schedule would remain at the curtailed level in interval 2.

The proposed single intra-hour schedule change of intertie schedules will work as follows for an increment:

- Assume an hourly block import has bid of $50.00. In the hourly process to accept block schedules, the import is accepted for 50 MW.
- The lowest transmission profile tagged in a neighboring balancing authority at T-37.5 is equal to 100 MW. The ISO market optimization will not award energy schedules which exceeds the lowest transmission profile tagged at the start of the binding 15-minute market optimization.
- In interval 1 of the 15-minute market the LMP is $55.00, but is only economic for the balance of the hour at 50 MW, the energy schedule is unchanged and is paid $55.00.
- Then in interval 2, the 15-minute market determines that the import is economic for the remainder of the hour at 100 MWW, the energy schedule is increased to 100 MW and will remain at that level for interval 3 and interval 4.
- In interval 3 and interval 4, the import is paid the relevant LMP for 100 MW

In the revised straw proposal, the ISO proposed that the hourly block schedule with the option to curtail once is eligible for real-time bid cost recovery if it is decremented from its day-ahead schedule. However, after considering stakeholder feedback, the ISO agrees that a subset of hourly block schedules should not be eligible for bid cost recovery as this could provide disincentives to move to 15-minute scheduling. In addition, the opportunity to curtail once per hour mitigates the risk of exposure to LMPs below a resources bid price if system conditions change between the hour-ahead process to accept block schedules and the financially binding 15-minute market.

5.2.3 Economic Bid Participation in 15-Minute Market

There may be instances when an intertie resource submits an economic bid and is willing to be rescheduled in the 15-minute market, but is not accepted through the market optimization of the hourly process to accept block schedules. In the event that an intertie resource does not want to participate in the 15-minute market for a quantity greater than an advisory energy schedule (including zero), the resource would simply update its transmission profile to the maximum amount it wants to make available to the 15-minute market prior to the start of the binding 15-minute market optimization (T-37.5 minutes). If the resource does not have a transmission profile in excess of its advisory energy schedule, the resource cannot be scheduled for energy in the 15-minute market higher than its advisory energy schedule.

Intertie resources that participate in the 15-minute market are eligible for bid cost recovery.

5.3 15-Minute Market Process

Under the proposed 15-minute market design, 15-minute energy schedules will be financially binding for imports, exports, internal resources, and load. The ISO will leverage the existing real-time unit commitment process which currently co-optimizes energy and ancillary services, but only results in financially binding unit commitment and ancillary services awards. The current co-optimization calculates non-binding 15-minute energy schedules and LMPs. The 15-minute market will clear against the ISO's forecast of real-time demand.

In order to minimize seams issues with intertie transactions, the ISO will align the 15-minute market timeline so that the e-tag deadline at twenty minutes in advance of flow can be met for the energy schedules dispatched by the 15-minute market runs. Aligning the 15-minute market timeline to allow for tagging energy schedules for the 15-minute markets requires that the ISO begin the market optimization 37.5 minutes prior to the binding interval, earlier than the current 22.5 minutes prior to the binding interval, so that the ISO can issue awards at 22.5 minutes prior to the binding interval. This allows 2.5 minutes for intertie transactions to submit updated e-tags reflecting the binding energy schedule twenty minutes prior to flow. Only the energy portion of e-tags for energy schedule changes made in the 15-minute market need to be updated, because market participants will presumably submit a tag with an hourly transmission reservation prior to the start of the hour. During the implementation phase of these market design changes, the ISO will assess if the 15-minute market solution time can be optimized such that the results could be published earlier allowing more time for updating of energy schedules on e-tags. Figure 3 below shows the timeline for the second financially binding 15-minute market interval in a trade hour.

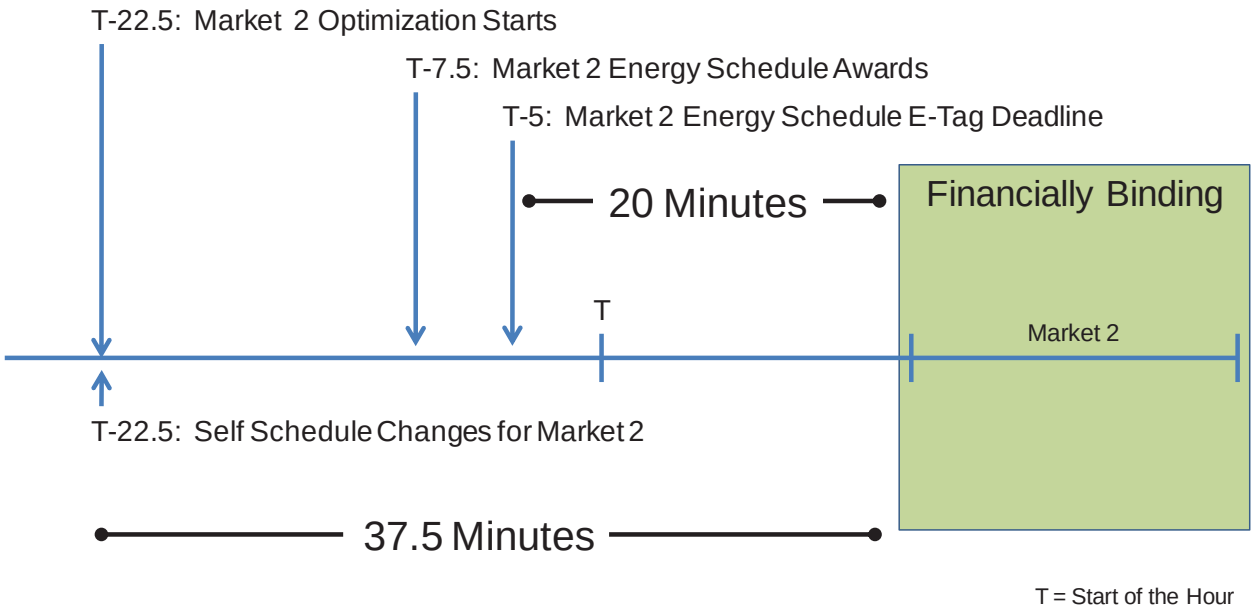

Figure 3 - Timeline of 15 Minute Real-Time Processes

The ISO does not believe that in the near future there will be changes to the WECC interval ramping protocols. Currently hourly changes have a 20-minute ramp and 15-minute changes will have 10-minute ramps. The ISO will use the appropriate ramp profile to ensure awarded 15-minute schedules are feasible. As business processes evolve within WECC and the checkout of energy schedules becomes more automated, the ISO anticipates the 15-minute market could be pulled in closer to the binding interval.

Based on discussions with neighboring balancing authorities and recognition that the 2.5 minutes between 15-minute market awards and the tagging deadline requires automation, the ISO will update energy schedules on e-tags for the 15-min market awards within an hour. Neighboring Balancing Authority Areas have stated this will expedite their subsequent approval of the updated tags. This will help ensure that energy schedule changes based upon the results of the 15-minute market will be reflected in e-tags prior to the T-20 tagging deadline and limit the market participant's role to approving the updated tag. This is comparable to the timeline to internal generation dispatches in which the ISO issues the dispatch 2.5 minutes prior to the start of the applicable dispatch interval. However, an important difference is the generation behind imports will have an additional fifteen minutes compared to internal generation before it has to change its output – the tagging deadline is at T-20 while the ramp for intrahour 15-minute schedule changes starts at T-5.

Scheduling coordinators can opt out of having the ISO update the energy schedule on e-tags. The scheduling coordinator is then responsible for updating the e-tag with the 15-minute energy schedule within the 2.5 minutes before the tagging deadline. The scheduling coordinators decision to opt out will be reflected in the bid. For multiple tags related to the same energy schedule, ISO will adjust energy schedules on a pro-rata basis.

As described above in Figure 3, beginning the run of the optimization for the15-minute market at 37.5 minutes prior to the binding interval is 15 minutes earlier, than the current real-time unit commitment process, which begins at 22.5 minutes prior to the binding interval. The ISO has analyzed market data to estimate the impact of extending this timeline on the accuracy of

estimating system conditions (i.e. projected price). This analysis has compared both the differences between RTUC 15-minute market results for the current binding RTUC interval compared to the binding RTD intervals within each 15-minute period, as well as the RTUC 15-minute market results for the first advisory interval to the corresponding binding RTD intervals. The comparison of the first advisory RTUC interval to the binding RTD intervals is analogous to the ISO proposal for the new 15-minute market. The analysis shows that while the tagging timeline required the ISO to start the new 15-minute market earlier than the existing RTUC process, there is not a material difference in system condition changes that would negatively impact the improved market efficiency of implementing the 15-minute market.

5.4 5-Minute Real Time Dispatch

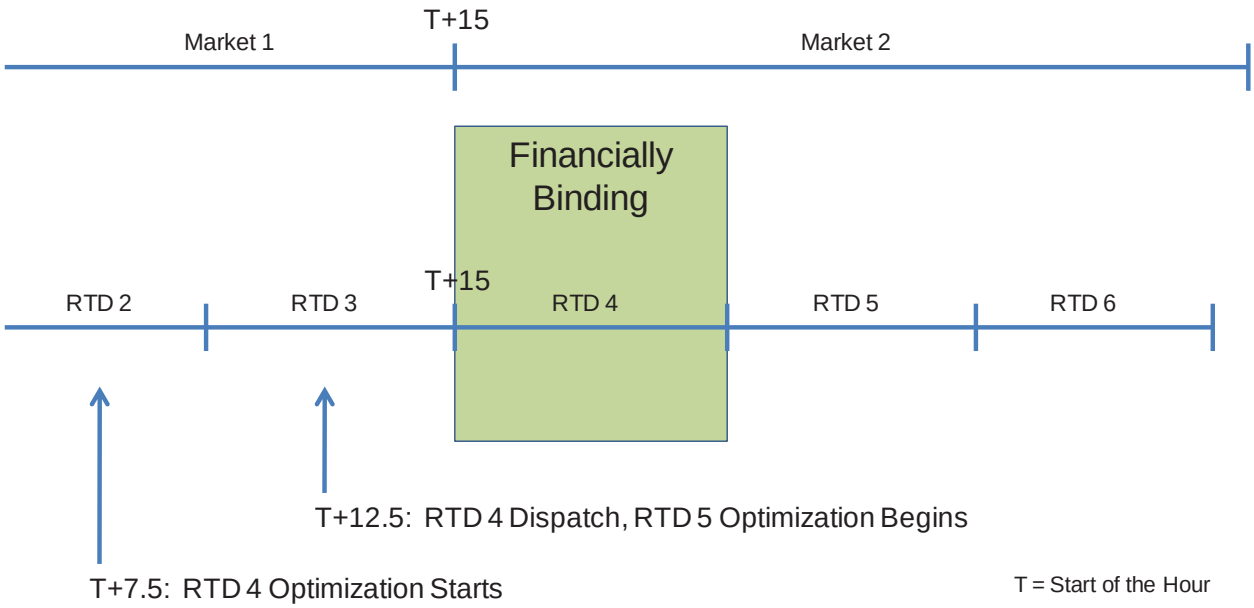

Figure 4 - Timeline of 5 Minute Real-Time Dispatch

The ISO is proposing no changes to the 5-minute real-time dispatch timeline or business processes. The market optimization determines the financially binding dispatch and communicates to resources 2.5 minutes prior to the binding RTD interval. Figure 4 above shows the market timeline for the first RTD run in the binding 15-minute market 2 shown above. The 5-minute RTD will continue to clear against the ISO's real-time demand forecast.

It is important to note that the market timeline of RTD minimizes potential "implicit" virtual bidding on the interties. It is argued that intertie schedules may not tag their energy schedule awarded in the 15-minute market so that they will be settled at a lower RTD price for their deviation. Since the 15-minute market schedule is determined at 22.5 minutes prior to the start of the first binding RTD interval, the intertie schedule would not have visibility to actual RTD pricing as it is published 2.5 minutes prior to the biding interval before the tagging deadline of 20-minutes prior to the binding RTD interval. The ISO will monitor for potential "implicit" virtual bidding and if this behavior results in reliability issues or market inefficiencies the ISO would consider an uninstructed deviation penalty.

6 Settlement with 15-Minute Market

6.1 Energy Deviations for Generation and Intertie Transactions

With the introduction of financially binding energy schedules for the 15-minute market, energy in the various markets will be settled as follows[4]:

- Day-ahead energy schedules will be settled at the day-ahead LMP.
- The difference between the 15-minute market energy schedule and the day-ahead energy schedule will be settled at the 15-minute market LMP.
- The difference between RTD energy dispatch and the 15-minute market energy schedule will be settled at the RTD LMP.
- Instructed imbalance energy will be calculated every fifteen minutes for the 15-minute market and every five minutes for 5-minute market. The 15-minute instructed imbalance energy will be based on a flat 15-minute energy schedule across the relevant 15-minute interval and settled at the 15-minute LMP. The 5-minute instructed imbalance energy will be based on the Dispatch Operating Point (DOP), which is the dispatch trajectory between consecutive 5-minute dispatches considering the applicable dynamic ramp rate, and it will be settled at the 5-minute LMP. Uninstructed imbalance energy will be calculated every five minutes and settled at the 5-minute LMP. With the transition to 5-minute meter data, there will be no reason to distinguish between tier-1 and tier-2 uninstructed imbalance energy; all uninstructed imbalance energy will be calculated and settled in one tier.
- Real-time bid cost recovery will include revenues and costs from both the 15-minute market and RTD using the same hourly bid curve.
- Current make whole payments due to price corrections for export resources will be provided for both 15-minute and, if applicable, for 5-minute LMP corrections.

All intertie transactions will be settled in a consistent manner to internal resources. For intertie transactions, if a 15-minute self-schedule or awarded energy schedule is not e-tagged at twenty minutes prior to flow, the deviation or operational adjustment will be settled at the RTD price in the same manner as internal generation deviations to 15-minute energy schedules. For hourly block schedules, if the energy schedule is curtailed for physical reasons the self-schedule for each of the 15-minute market can be updated. If the outage or other schedule change (e.g., a schedule that is affected by outages or changes in variable energy resources' output in other balancing authority areas, by priorities of transmission service using non-ISO transmission providers, or similar reasons) is known prior to the start of the 15-minute optimization, the 15-

[4] The ISO has posted an illustrative spreadsheet of energy settlement with the revised straw proposal.

minute energy schedule will reflect the schedule change.[5] Thus, it would not be considered as a deviation between the 15-minute energy schedules which is settled at the RTD price.

The ISO proposes to meter generation every five minutes. Currently the ISO receives 5-minute meter data from internal generation, but then sums two five minute intervals to align with the ten minute settlement interval for purposes of calculating uninstructed imbalance energy.

Several stakeholders have advocated that deviations between the 15-minute market and RTD should be settled at the "worse of" price. For example, positive generation deviations would be paid the lower of the 15-minute price or RTD and negative deviations would be charged the higher of the 15-minute price or RTD. This is intended to incentivize resources to follow RTD dispatch since uninstructed deviations can never be profitable, but would be a departure from the settlement of deviations common in LMP markets, i.e. deviations are paid/charged at the price existing in the timeframe in which the deviation occurs. The ISO believes that if additional measures are needed, such as implementation of uninstructed deviation penalties, they should be reviewed after implementation the new 15-minute market.

In addition, several stakeholders have expressed concern that intertie schedules could engage in "implicit" virtual bidding between the 15-minute market and RTD. Since deviations are settled at the RTD price, an intertie schedule could exploit predicted differences between the 15-minute market price and the RTD price. Based on the historical data provided, no analysis has concluded that there is a predictable price difference. The tagging deadline for 15-minute energy schedules is 20 minutes prior to flow. Since the pricing results of the first RTD interval are not published until 2.5 minutes prior to flow, there is not the ability for an intertie resource to observe the first RTD prices and then not tag their energy schedule from the 15-minute market. The ISO believes that if additional measures are needed, such as implementation of uninstructed deviation penalties, they should be reviewed after implementation the new 15-minute market.

6.2 Hourly Block Process Decline Charge

Since the hour ahead process to accept block schedules does not result in financially binding settlements there can be instances where a resource does not bear a financial consequence if it is unable to meet its advisory energy schedule. The following are examples:

- An incremental export when constrained in the import direction;
- An incremental import when constrained in the export direction;
- An import from a variable energy resource that overstates its expected energy output.

Similar issues occur under the current HASP market design, since deviations or operational adjustments from the hourly HASP schedule are settled at the HASP price. In order to address potential gaming concerns, the HASP Schedules Decline Charge was implemented. The HASP import (exports) schedule decline charge monthly threshold is the highest of 300 MW or 10% of

[5] *See* Order on rehearing and clarification and granting motion for extension of time re Integration of Variable Energy Resources under RM10-11, PP 5

total imports (exports). The price applied to the MW above the threshold is the maximum of $10.00 or 50% of the HASP LMP.

Economic dispatch in the 15-minute market, dynamic transfers and VERs using the ISO forecast will be exempt from the hourly block process decline charge.

Under the ISO's proposed real-time market changes, an hourly block process decline charge, similar to the current HASP Schedules Decline Charge would apply to various intertie schedules. The intent of this charge is to penalize energy schedules that are not delivered or VERs forecasts that are over-stated that do not otherwise incur a financial obligation in the market for the undelivered energy. The proposed hourly block process decline charge is as follows:

Hourly Block

- Imports and exports that are incremental to day-ahead schedules and that result from the hour-ahead process to accept block schedules are subject to the hourly block process decline charge to the extent the decline is made prior to the start of the market run for the applicable 15-minute interval. This is because the resource would then be dispatched down prior to the 15-minute interval and the resource would not receive a financially binding dispatch despite tying up intertie capacity in the hourly process. The declines charge will not apply if the decline is made after the start of the market run for the applicable 15-minute interval because in this case the resource will receive a financially binding 15-minute market dispatch and be subject to the RTD price for the undelivered portion.

- If a resource has a day-ahead schedule, any operational adjustment will be settled at the 15-minute price, thus the day-ahead schedule is not considered in the decline charge.

Hourly Block with Schedule Change

- Imports and exports that are incremental to day-ahead schedules and that result from the hour-ahead process to accept block schedules are subject to the hourly block process decline charge to the extent the decline is made prior to the start of the market run for the applicable 15-minute interval. This is because the resource would then be dispatched down prior to the 15-minute interval and the resource would not receive a financially binding dispatch despite tying up intertie capacity in the hourly process. The declines charge will not apply if the decline is made after the start of the market run for the applicable 15-minute interval because in this case the resource will receive a financially binding 15-minute market dispatch and be subject to the RTD price for the undelivered portion.

- If the incremental import or export is schedule is curtailed through the 15-minute market, the 15-minute interval where the resource follows the ISO instructions are no subject to the hour ahead schedules decline charge.

Variable energy resource using its own forecast

- To address concerns that variable energy resources will overstate their forecast in the hourly process to crowd out hourly block schedules from conventional resources,

imports from variable energy resources are subject to the hourly block process decline charge to the extent the resource over-forecasts over the month.

- For each hour, the ISO will compare maximum 15-minute financially binding schedule (that is submitted 37.5 minutes prior to flow) to the maximum 15-minute advisory schedule from the hour-ahead process to accept block schedules (based upon the hourly forecast received 75 minutes prior to flow). Over the course of the month, positive deviations can offset negative deviations in monthly threshold calculations. Thus if the maximum advisory schedule exceeds the actual financially biding schedule by the threshold over the course of the month, the hourly forecast has on average overstated the actual production and as a result, crowded out hourly block schedules that otherwise might have been awarded if the forecast used in the hourly process was not biased upward.

6.3 Settlement of Load

As previously described, both the 15-minute market and RTD will clear against the ISO forecasted demand. Non-participating Load will not be allowed to bid in to the 15-minute market or RTD. (Participating Loads, Proxy Demand Resources, and other dispatchable demand response will continue to participate in the 15-minute market and RTD.) Differences in load from day-ahead schedules will be settled at the hourly weighted average LMP of the 15-minute market and RTD by DLAP. The LMPs will be weighted by the MW cleared in the two respective markets and will be bounded by the most extreme LMP from those relevant intervals. A spreadsheet had been posted with the revised straw proposal that illustrates the load settlement.

The use of DLAP load forecasts to determine the hourly weighted average price will require additional payloads to settlements. The DLAP load forecasts will be included in the settlement data provided to load serving entities.

As illustrated in the spreadsheet example, since load continues to be metered on an hourly basis, the weighted average approach does result in neutrality charges that are allocated to load. SCE requested that these neutrality charges be allocated to all deviations from net load – ISO load forecast less variable energy resources forecast. This is not appropriate as variable energy resources are settled in the 15-minute market based upon their forecasted output. Thus the hourly weighted average is only applicable to Load which is metered hourly. The variable energy resource forecast error is settled correctly as deviations between the 15-minute market and RTD. As a result, only ISO load forecast result in the neutrality charge of the Load settlement.

The settlement of load based upon the weighted average price is only applicable for load that is metered hourly. Load following MSS will be settled similar to the current market design. In the 15-minute market, load following MSS will need to balance their load and supply. In RTD, the load following MSS must balance their load and supply in the five minute interval within the established threshold or be subject to MSS load following deviation penalties. Similarly to internal generation, load following MSS settlement intervals will be changed from a 10-minute granularity to a 5-minute granularity.

6.4 Inter-SC Trades

The proposed changes to the real-time market will not result in inter-SC trades becoming a 15-minute product. Inter-SC trades will remain an hourly product and will be settled in real-time at the simple average of the four 15-minute market LMPs.

6.5 Grid Management Charge

The ISOs Grid Management Charge (GMC)[6] consists three main cost categories or buckets (Market Services, System Operations, and CRR Services), and four transaction fees (bid segment fee, inter SC trade fee, CRR bid fee, and SCID fee).

Since the 15-minute market is now financially binding for both energy and ancillary services, the ISO proposes to include energy and ancillary services awards in two GMC charge codes: Market Services and the Bid Segment Fee.

The Market Services charge code is designed to recover costs the ISO incurs for running the markets. As such, this charge code will be applied to each scheduling coordinator's gross absolute value of awarded MWh of energy and MW per hour of ancillary services each market.

The Bid Segment fee is set at $0.005 per bid segment and is applied to all bid segments submitted.

7 Variable Energy Resources

7.1 Participating Intermittent Resource Program (PIRP)

In return for providing meteorological data to allow production forecasting, PIRP resources were allowed to net over the month uninstructed imbalance energy if they submitted the ISO production forecast to establish their 5 minute instructed imbalance energy (hourly forecast divided by 12). FERC Order 764 now requires that variable energy resources provide meteorological data and the ISO believes that with the improved opportunities for variable energy resources to self-schedule their production closer to real time, the existing PIRP should be modify provisions to net uninstructed imbalance energy.

Currently PIRP resources must submit the ISO hourly forecast generated 90-105 minutes prior to the hour to be eligible for monthly netting of uninstructed imbalance energy. This hourly forecast is used to establish instructed energy in RTD dispatch intervals by dividing the total hourly forecast by twelve. If the PIRP resource does not submit the hourly forecast, the hour is excluded from monthly netting of uninstructed imbalance energy. If the PIRP resource does not have a day-ahead schedule (which is very common), the resource's scheduled instructed energy output based on the hourly forecast is settled at the average hourly RTD price. Instructed energy is settled at the 10-minute weighted average of the two RTD intervals, but since PIRP instructed energy is flat for the hour, the price is equal to the average hourly RTD price. For non-PIRP resources, uninstructed energy is settled at the 10-minute average price of the two RTD intervals. For PIRP resources, the uninstructed imbalance energy is netted over the month and paid (or charged) the average monthly LMP.

In the Renewable Integration: Market and Product Review Phase 1, several stakeholders argued that PIRP should not be eliminated until changes were made to the real-time market that

[6] Additional information on the Grid Management Charge is available at http://www.caiso.com/informed/Pages/StakeholderProcesses/Budget-GridManagementCharge.aspx

allowed for closer and more granular schedule updates. The changes made as a result of this stakeholder initiative will do this. Under the 15-minute market settlement, variable energy resources will now be able to secure a forward energy position in the 15-minute market, based upon a forecast received 37.5 minutes prior to flow. This 15-minute price should be less volatile than the RTD price because resource commitment decisions can be made, greatly reducing variable energy resources' exposure to price volatility.[7] Variable energy resources will only be subject to the RTD price for forecast error between the 15-minute schedule and RTD interval and for ramping between 15-minute schedules. This amount of energy subject to the RTD price will be significantly less than under the current market design in which all of variable energy resources output is subject to the RTD price (unless scheduled in the day-ahead market).

With 5-minute metering and if the resource elects to use 5-minute forecast granularity, both instructed and uninstructed imbalance energy are settled at the same 5-minute LMP.

7.1.1 PIRP Modifications

To align with the proposed real-time market structure changes, the ISO proposes the following modifications to the PIRP. The scheduling opportunities based upon forecast closer to actual production significantly reduce exposure to uninstructed imbalance energy; however, VERs will be settled on instructed deviations between the 15-minute schedule and RTD.

The following outlines how the PIRP would function under the new real-time market structure:

- PIRP certification remains unchanged.
- PIRP participation will be identified in the ISO's master file. No hourly option to be in/out PIRP.
- Scheduling coordinators will not have to send back the ISO forecast which reduces scheduling delays and potential errors.
- Economic bids can be submitted hourly for use in the 15-minute market and RTD to award an energy schedule or dispatch different than the resource's forecast.
- PIRP will use the ISO forecast with a two-hour look-ahead and five minute granularity.
- The 15-minute self-schedule will be the sum of the relevant three five minute forecasts received 37.5 minutes prior to flow.
- The RTD instructed energy the self-schedule based upon the relevant five minute forecast received 7.5 minutes prior to flow.
- RTD instructed energy deviations from the 15-minute schedule divided by three will be settled at the RTD LMP.

[7] The ISO posted DA, advisory RTPD and the weighted average RTD price data on the FERC Order 764 market design changes website on October 26, 2012

- Uninstructed imbalance energy will be the difference between the meter and the RTD instruction based upon the forecast from 7.5 minute prior to flow and will settle at the RTD price.

- The monthly netting of uninstructed imbalance energy will be eliminated.

The ISO proposes to establish a process to identify existing PIRP resources that have operational characteristics that require additional protective energy settlement measures under the FERC Order No. 764 market design changes. This process will be used to identify if there are any impacted resources, so that mitigation measures can be developed that address the specific issues identified.

The ISO proposes that PIRP resources will have 30 days from the May Board of Governors meeting to notify the ISO that they meet the specified criteria and they request mitigation measures to address their operational characteristics. The ISO proposes that it would develop mitigation only if resources are identified that meet the criteria below:

1. A material portion of the existing plant's output uses technology that lacks the ability to receive and follow ISO curtailment dispatches; and
2. The PIRP resource bears the imbalance market costs under its existing PPA.

Based on data provided by the IOUs, we anticipate the number of resources meeting these criteria to be extremely limited and therefore believe it is best to address their particular circumstances on a case by case basis. If the ISO identifies any resources that meet the criteria above, it will commence a stakeholder process to develop any protective measures needed to address the operational characteristics of these resources. The possible set of protective measures to be developed is not limited to monthly imbalance netting in some form and could be provided in an alternative settlements arrangement. This approach will insure that the protective measures will not be overly complex relative to the issues that need to be mitigated, and will be narrowly tailored to address any facilities identified in this process to have met the criteria above.

7.2 Update of 15-Minute Self-Schedule

In order to use the latest possible forecast under these proposed market changes, variable energy resources will provide at a minimum a two-hour rolling forecast with fifteen minute granularity, although variable energy resources will be able to submit a 5-minute forecast to be used in the RTD dispatch as described further below. The forecast will be received by the ISO for the binding interval at 37.5 minutes prior to flow (the start of the market optimization for the binding interval). If no forecast is provided, the ISO will use the resource telemetry for dispatch.

As part of the Dynamic Transfer stakeholder initiative, variable energy resource that are dynamically scheduling can provide a two-hour rolling forecast with five minute granularity. The ISO proposes to also allow internal variable energy resources to optionally provide the same forecast granularity and will use the average of the projected energy output for the three 5-minute forecasts to determine the self-schedule for the binding 15-minute market interval. The ISO will use the forecast data received 37.5 minutes prior to start of the market optimization of the binding 15-minute market.

Variable energy resources will have the option to use the ISO forecast or their own forecast. Variable energy resources pay $0.10 per MWh for the ISO to provide forecasting services. If a variable energy resource elects to use its own forecast, it will be subject to the modified HASP schedules decline charge from the hourly process to accept block schedules. There are no

other settlement differences if the ISO forecast or resource's forecast is used in the 15-minute market or RTD.

In the resource's master file, variable energy resources will select if they are using the ISO forecast or their own forecast. The ISO's master file update process takes approximately 7-10 business days for changes to become effective in the market. In addition, the ISO will develop a certification process to approve variable energy resources to use their own forecast. The ISO will reserve the right to cancel a variable energy resource's ability to use their forecast if the resource's forecast is significantly less accurate than the ISO forecast.

7.3 Instructed energy in RTD

If the variable energy resource forecast uses 15-minute granularity, the ISO will divide the 15-minute forecast by 3 and return this value as the RTD instructed energy. For example, assume the 15-minute forecast was for 30 MWh. For each of the three relevant RTD intervals the instructed energy will be 10 MWh.

If the variable energy resource forecast uses 5 minute granularity, then the ISO will then use the 5-minute forecast available prior to the start of the RTD optimization to determine the instructed energy of the resource. RTD will return the 5-minute forecast value as the instructed energy for the binding RTD interval.

7.4 Economic Bid with Forecast Used to Cap Bid Curve

In the Flexible Ramping Product[8] stakeholder initiative, the ISO has proposed to allow decremental bids from variable energy resources that submit real-time self-schedules. The ISO believes that variable energy resource can be suppliers of the flexible ramping product in the downward direction (FRD). By fully participating in the market and providing the flexible ramping product, variable energy resources will offset, at a minimum, the other costs associated with fully participating in the market. A key requirement for providing the flexible ramping down product is that the resource must participate in the market by submitting an energy bid to be used by RTD.

With the implementation of FERC Order 764, there are minor modifications to the decremental bidding proposal discussed in the flexible ramping product. On an hourly basis, variable energy resources that wish to be economically dispatched below their self-schedule based on their forecast and in the future participate in the flexible ramping down product will provide an energy bid that will be used to clear in both 15-minute and 5-minute markets, along with the resource's ramp rate. In both markets, the ISO will utilize the resource's or ISO forecast as the upper bound for the energy dispatch when considering the economic bid curve in both 15-minute and 5-minute. A variable energy resource can be awarded flexible ramping down based upon the amount it can ramp down in five minutes, which is the same rule for any other resource providing FRD. The settlement of energy dispatches and flexible ramping down awards in the 15-minute market and RTD is the same as for any other resource.

Beyond the flexible ramping product, economic bids from variable energy resources can protect against negative prices during periods of over-generation. The ISO bid floor is being reduced from –$30.00 to -$150.00 in Fall 2013. The lower bid floors provide additional incentives for variable energy resources to provide economic bids to ensure that their forecast is only

[8] Additional information on the Flexible Ramping Product stakeholder initiative is available at http://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleRampingProduct.aspx

scheduled if the LMP is greater than their bid. The ISO is evaluating the implementation of PIRP economic bidding in Fall 2013 which is earlier than the other Order 764 changes planned for in Spring 2014. This implementation will allow the PIRP resources to submit energy bids (without self-schedule) and will use the PIRP forecast in RTD as the upper bound for the energy dispatch. In the intervals that the ISO dispatches a PIRP resource different from the PIRP forecast, the resource will not be eligible for the PIRP monthly netting of uninstructed imbalance energy for the applicable trading hour.

8 Convergence Bidding

When the ISO implemented convergence bidding on February 1, 2011, market participants had the ability to submit virtual bids on the intertie scheduling points in the ISO market. On November 28, 2011 the ISO suspended convergence bidding on the interties because of market inefficiencies and excessive real-time imbalance energy offset uplift charges attributable to convergence bidding on the interties.

8.1 Settlement in Real-Time

Under the proposed 15-minute market design, the ISO proposes to allow convergence bidding on internal nodes and intertie scheduling points. With the implementation of 15-minute market settlement, the ISO will liquidate convergence bidding positions in the same market optimization as physical bids for both internal resources and interties. Virtual supply awards will receive the day-ahead LMP and pay the 15-minute market LMP. Virtual demand awards will pay the day-ahead LMP and receive the 15-minute market LMP.

The ISO proposes not to allow convergence bidding between the 15-minute market and RTD. Unlike the day-ahead market, load will not be able to economically bid in the 15-minute market, thus it would be inappropriate to allow virtual demand to bid in the 15-minute market. In addition, the ability for physical resources to update their 15-minute schedule every fifteen minutes reduces the duration a resource is exposed to 5-minute deviations for an outage.

The ISO proposes to also modify its e-tagging rule, designed to deter implicit virtual bidding, to state that an intertie transaction must be tagged at the time of the hourly process for an intertie transaction originally scheduled in the day-ahead market to be bought back at a profit in the real-time market. The current rule only requires an e-tag to be submitted at some point before the HASP, but does not require the tag to be maintained through the HASP.

8.2 Day-Ahead Dual Constraint Issue

During the time convergence bidding was allowed on the interties, the ISO saw cases where physical export bids are clearing the market at LMPs that are inconsistent (higher) than the submitted bid for the scheduled resource. Market participants raised concerns regarding the negative impact this pricing inconsistency may have on their settlement outcome.

Under the previous design for convergence bidding on the interties, the ISO enforced two constraints at scheduling points: (1) net physical schedules across each scheduling point, ignoring the accepted virtual schedules to ensure that the physical schedules are within the established scheduling limit for that scheduling point and (2) physical and virtual imports net of physical and virtual exports must also be within established scheduling limits for that scheduling point.

In the Intertie Pricing and Settlement[9] stakeholder holder initiative the ISO proposed an alternative solution. The ISO proposed to eliminate the "physical only" constraint in the day-ahead market. However, in order to comply with WECC interchange scheduling requirements, based on an intertie's ITC, the ISO would impose a limit on the number of e-tags it will accept for IFM physical market awards.

The ISO proposes to establish the number of e-tags it will accept by enforcing the "physical only" constraint in RUC. The ISO will use penalized energy bids, such as applying a -$250 adder to IFM bid of cleared IFM schedules. This will have the effect of creating a merit order list of IFM schedules which with ISO will accept day-ahead e-tags. The results of the RUC process to determine which IFM schedules can be tagged will be published at the same time as day-ahead market results. IFM schedules that are not allowed to tag in the day-ahead, due to the RUC results, will not be subject to the existing HASP reversal rule. For settlement purposes, these schedules will be assumed to have tagged prior to the start of the hour ahead process to determine block schedules. In addition, IFM schedules whether tagged or not tagged will have scheduling priority over incremental schedule submitted in real-time. This scheduling priority is the same as exists in the current market.

The past rationale for the physical import and export constraints is that they prevented physical intertie market awards from exceeding an intertie's capacity. However, based on further consideration of the WECC reliability standards, the standards only require that total tagged interchange not exceed an intertie's capacity[10]. Thus, physical intertie market awards could potentially exceed an intertie's capacity, but the ISO would only accept e-tags for a total net interchange up to the intertie's capacity. In the hourly process to accept block schedules and the financially binding 15-minute market, the net physical intertie market awards would then be reduced to the intertie's capacity.

Some market participants have expressed concerns that allowing physically infeasible market awards and imposing a tagging limit would yield undesirable outcomes. First, parties are concerned that giving a physical resource a market award and not allowing it to tag would put the market participant at risk of violating WSPP Schedule C contracts that require market awards be tagged by 3:00 pm of the day prior to delivery. The ISO recognizes that such an approach may lead to e-tags not being accepted but observes that even under the current market design there is no assurance that a physical intertie bid will clear the IFM and consequently be allowed to tag. In addition, the ISO observes the following:

- The conditions under which a physical intertie bid clears the IFM but would not be allowed to tag are the same conditions under which the a physical intertie constraint was binding but the physical plus virtual intertie constraint was not binding previous to virtual bidding on the interties being suspended (i.e. virtuals providing counterflow to physicals to meet the tie constraint). As this circumstance did not occur frequently, the ISO anticipates that circumstances in which tags would potentially not be accepted for day-ahead physical intertie awards will occur relatively infrequently, and when it did occur, the amount of tags that would be cut would be small.

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9 Additional information on the Intertie Pricing and Settlement stakeholder initiative is available at http://www.caiso.com/informed/Pages/StakeholderProcesses/IntertiePricing_Settlement.aspx

10 WECC standard INT-006-3 requirement R1.2 http://www.nerc.com/files/INT-006-3.pdf

- E-Tags may be cut for physical market awards under the current market rules. For example, e-tags for physical imports may be cut if e-tags are not submitted for physical exports providing counterflow on an intertie with import congestion.

Nevertheless, in the case an IFM physical intertie award is not allowed to tag prior to the hour ahead process to accept block schedules, two circumstances could result:

- The IFM physical intertie award clears the hour-ahead process to accept block schedules. Subsequently, the ISO would accept the e-tag for the market.

- The IFM physical intertie award does not clear or is reduced in the hourly process to accept block schedules. In this case, it is possible that the IFM physical intertie award would be subject to the existing HASP buy-back rule that specifies that untagged imports be bought back at the higher of the IFM or 15-minute price (and that untagged exports are sold back at the lower of IFM or 15-minute price). The ISO proposes that the HASP buy-back rule not be applied to IFM awards that were not tagged as a result of the merit order approval process. These IFM awards will be assumed tagged for settlement purposes.

8.3 Position Limits

Given the uncertainty of the market impacts of convergence bidding at intertie scheduling points, at the onset of convergence bidding the ISO imposed a position limit on convergence bids of 5 percent of an intertie's average transfer capacity per SC at each intertie. If no adverse market impacts were observed, the position limits were to increase from 5 percent to 25 percent after eight months of implementation. Then they were to increase to 50 percent after 12 months from implementation. After 16 months there would be no position limits. This phasing in of convergence bidding enabled the market participants to gain experience under the new market design and allow the ISO and stakeholders to address any unanticipated market issues prior to adding the complexity of convergence bidding.

In the revised straw proposal, the ISO proposed changing the position limit to 10 percent of the largest intertie across all interties scheduling points for each scheduling coordinator[11]. This position limit would remain in place for at least six months after convergence bidding on the interties is reopened. Before lifting this limit, the ISO, in conjunction with the DMM, would examine the performance of convergence bids on the interties to determine if additional measures need be implemented to prevent inefficient market participant behavior or if the position limits can be raised. This was the same proposal as the ISO made during the Intertie Pricing and Settlement stakeholder initiative.

Upon further reflection, the ISO believes the implementation costs of redesigning the position limits on the interties outweigh the benefits changing the basis from intertie scheduling point to scheduling coordinator. In addition, many stakeholders opposed the lack of a firm timing for elimination of position limits. As a result, the ISO proposes to use the same position limit methodology and timing of increases used at the onset of convergence bidding.

Many stakeholders continue to express concern of immediately reinstating convergence bidding with the FERC Order No. 764 design changes. The FERC Order No. 764 real-time market

[11] Currently, the single largest intertie is the Tracy intertie at 3,829 MW

changes will be a relatively major change to the market, especially to the scheduling and pricing of intertie transactions. In addition, the ISO is planning to implement the Energy Imbalance Market in Fall 2014 which will expand the real-time market, both the 15-minute market and RTD, to include other balancing authorities. The ISO is proposing an initial twelve month period, without intertie convergence bidding, to allow market participant's to observe the operation of the new 15-minute market under various seasonal conditions. This is similar to the initial operation of the nodal market, in which there was an initial period without convergence bidding to allow the ISO and stakeholders to address any unanticipated market issues prior to adding the complexity of convergence bidding.

The position limits will be based on the average transfer capacity of each intertie. The limit per scheduling coordinator and timing will be as follows:

0%	15-minute market implementation to 12 months
5%	12 months to 20 months
25%	20 months to 24 months
50%	24 months to 28 months
No Limit	28 months

9 Next Steps

The ISO plans to discuss this addendum to the draft final proposal with stakeholders during a conference call to be held on May 1. The ISO will answer questions relating to the changes in this addendum to the draft final proposal on that call and will provide an opportunity for stakeholders to share their comments. The ISO plans to present its FERC Order No. 764 design changes proposal to its Board of Governors at their May meeting.

Attachment E – May 8, 2013 Board Memorandum

Real-Time Market Design Enhancements Related to Order No. 764

California Independent System Operator Corporation

November 26, 2013

Memorandum

To: ISO Board of Governors

From: Keith Casey, Vice President, Market & Infrastructure Development

Date: May 8, 2013

Re: **Decision on FERC Order No. 764 Market Design Changes**

This memorandum requires Board action.

EXECUTIVE SUMMARY

This memorandum describes enhancements Management proposes to make to the real-time market to effectively and efficiently integrate a large amount of renewable variable energy resources into the California ISO's resource fleet. The proposed enhancements will also meet the ISO's compliance obligations under FERC Order No. 764 issued last year. The order required that all FERC-jurisdictional transmission providers provide the opportunity for intra-hour schedule changes in 15-minute increments. This requirement is instrumental to facilitating these proposed enhancements that will create a market structure oriented around renewable resources while eliminating existing market inefficiencies.

Specifically, the ISO proposes to change intertie scheduling and settlement from an hourly to a 15-minute basis, and to establish a 15-minute settlement for internal resources and convergence bids. Management also proposes to retain the existing 5-minute dispatch to provide real-time balancing. Management proposes changes beyond the minimum requirements of Order No. 764, which would consist of only providing an option to schedule on a 15-minute basis on the interties, because the more comprehensive changes Management proposes provide numerous benefits, including:

- A market that is structured around the characteristics of variable energy resources. Not only do these changes accommodate scheduling variable energy resources over the interties, but they also allow all resources to be scheduled more effectively through more granular schedules with shortened forecast lead times.

- Elimination of the settlement uplift charges currently attributable to settling intertie resources at hourly prices while settling internal resources at 5-minute prices. The proposed changes will result in both intertie and internal resources being

scheduled and settled in the same market run. This will eliminate inefficiencies that currently occur, for example, when energy is sold at the interties in the hour ahead scheduling process and then bought back from internal resources in the 5-minute dispatch at higher prices.

- Comply with Order No. 764's requirements to allow for 15-minute energy scheduling, while including provisions for hourly intertie transactions to remain.

- Correct the problems that led to suspension of convergence bidding at the interties. Management proposes to reinstate convergence bidding at the interties after these market changes have been in place for 12 months. This is to allow for a "shakeout" period after the ISO puts these significant market changes in place.

Management proposes the following motion:

Moved, that the ISO Board of Governors approves the proposed market design changes in compliance with FERC Order No. 764 , as described in the memorandum dated May 8, 2013; and

Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposed tariff change.

DISCUSSION AND ANALYSIS

During the renewable integration market and product review phase II initiative two years ago, Management discussed a potential redesign of the real-time market consisting of a 15-minute internal and intertie resource scheduling, along with a new balancing product, such as a one-minute dispatch, that would meet energy imbalance needs in the timeframe between the 15-minute dispatch and real-time regulation. However, the ISO did not pursue this redesign because the stakeholder process concluded that balancing authorities in WECC were unlikely to adopt intra-hour scheduling in the foreseeable future.

Order No. 764 now provides an incentive for parties to move to more granular scheduling in the West. FERC jurisdictional balancing authorities in the WECC region, as well as some non-FERC jurisdictional balancing authorities, will now offer 15-minute scheduling, which the ISO will have to accommodate. Management proposes to add 15-minute schedules and settlement for both interties and internal resources, but proposes to keep the existing 5-minute dispatch for internal resources and dynamically-scheduled intertie resources rather than adopt a shorter duration balancing product. This is for two reasons: (1) it preserves the pricing information and incentives provided by the existing 5-minute dispatch, and (2) it greatly reduces implementation complexity, time, and costs by using existing market functionality. As a result, the ISO will be able to implement these changes in the spring of next year.

The following sections describe the various elements of Management's proposed real-time market changes:

Financially binding 15-minute energy schedules

The current real-time market is composed of three processes:

(1) The hour-ahead scheduling process establishes hourly financially binding energy schedules and ancillary services awards for intertie transactions.
(2) The real-time pre-dispatch runs every fifteen minutes to establish financially binding ancillary services awards and unit commitment for internal generation.
(3) The 15-minute energy schedules that result from this process are not financially binding under the current market structure.

By creating financially binding 15-minute energy schedules, the proposal aligns the financially binding settlement of energy schedules and ancillary services awards for intertie transactions, internal generation and load through the use of existing market functionality.

The following describes the salient features related to this new market element:

- The real-time market will include both 15-minute and 5-minute financially binding schedules and settlement:
    - It will produce 15-minute schedules and locational marginal prices for all resources, including internal and intertie transactions. Differences between these 15-minute schedules and day-ahead schedules will settle at the 15-minute prices.
    - The real-time market will maintain its existing 5-minute dispatch for internal resources, participating load, and dynamically scheduled intertie transactions. Differences between the 5-minute dispatch and the 15-minute schedule will settle at the 5-minute price.
    - The settlement and maximum metering interval will change from 10 minutes to 5 minutes
- The market process that will produce the 15-minute schedules and prices will begin 37.5 minutes prior to the 15-minute interval and will send the results to market participants 22.5 minutes before the applicable interval. This is designed to initiate the software run in as short of a time as possible prior to the 15-minute interval. Doing so allows the ISO to use the most current forecast for renewable generation which will maximize the accuracy of the market results while maintaining consistency with WECC's deadline for submitting e-tags for intertie transactions, which is 20 minutes prior to the interval. These proposed enhancements result in a significant reduction in lead time, and consequently a

reduction in renewable energy forecast error, compared to the hour-ahead scheduling process that currently schedules interties, which begins 75 minutes in advance of the relevant hour.

- Internal and dynamically-scheduled variable energy resources will be scheduled using resource-specific rolling multi-hour forecasts with 5-minute granularity, as follows:

    - 15-minute schedules will be based on the average of the relevant three 5-minute interval forecasts received 37.5 minutes in advance.

    - 5-minute dispatch will be based on the relevant forecast received 7.5 minutes in advance.

- The real-time market will continue to include an hour-ahead scheduling process. However, it will only be used to schedule intertie transactions that must be fixed for the hour. These fixed hourly schedules are no longer guaranteed the price projected by the hour-ahead scheduling process. Rather, they will be paid the price in each of the 15-minute settlement intervals during the hour they are scheduled.

- The ISO will settle load in the real-time market at load aggregation point prices calculated using an average of the 15-minute and 5-minute prices. The prices will be weighted by the respective load forecasts used by the 15-minute and 5-minute market runs. Load will continue to be metered hourly but will be settled on a 5-minute basis.

Intertie transactions

To accommodate the transition to the 15-minute market structure, Management's proposal includes several options for scheduling intertie transactions (i.e. imports or exports). These include mechanisms to facilitate scheduling variable energy resources and to accommodate hourly schedules. Hourly schedules may remain despite availability of 15-minute scheduling, especially during the transition period as 15-minute scheduling becomes more widespread.

The proposal includes several scheduling options to mitigate the transition challenges to moving to more granular intertie scheduling:

- **15-minute economic bid**: Market participants will be able to submit economic bids that the ISO can schedule in 15-minute intervals based on price. These transactions will be settled at the 15-minute price.

    These intertie bids will be cleared in the same optimization as internal resource bids. Consequently, with these proposed real-time market changes, intertie and internal resources will now compete and be priced on an equal basis.

- **Variable energy resource schedules**: Market participants will be able to schedule the output of variable energy resources in 15-minute intervals based on their forecast output. These transactions will be settled at the 15-minute price.

  This bidding option, along with the 15-minute economic bid option described above, make Management's proposed market changes compliant with Order No. 764's requirement to provide an option for 15-minute scheduling.

- **Fixed hourly self-schedules:** Market participants will be able to submit self-schedules that are fixed for the hour. These will be settled at the 15-minute prices over the operating hour.

- **Fixed hourly economic bid:** Market participants will be able to submit economic bids for intertie transactions that will be a fixed quantity for the hour and that the ISO can schedule based on price. The ISO will schedule these based on prices projected by the hour-ahead scheduling process, but these transactions will be settled at the actual 15-minute prices over the operating hour.

  Since the 15-minute prices the ISO pays for an import may end up being lower than the prices projected by the hour-ahead scheduling process that was used to clear a market participant's fixed hourly import bid, market participants may compensate for this risk by increasing their bid price. Conversely, as market participants may potentially pay more than their bid price for exports, they presumably will lower their bid prices for fixed hourly exports. This effect on the prices of fixed hourly intertie transactions is appropriate and desirable for two reasons: (1) it will transparently price the additional cost of fixed hourly schedules rather than allocating this cost to an uplift charge as is currently done, and (2) it will appropriately value fixed hourly intertie transactions relative to the greater value of 15-minute dispatchable intertie transactions.

- **Fixed hourly economic bid with single intra-hour schedule change:** Similar to the fixed hourly economic bid option described above, market participants will be able to submit economic bids for intertie transactions that will be a fixed quantity for the hour and that the ISO will schedule based on price. As in the previous option, the ISO will schedule these transactions based on prices projected by the hour-ahead scheduling process. However, this option allows for the schedule to be changed once per hour if the 15-minute prices meet criteria specified by the market participant. For example, the ISO would reduce an import schedule to zero if the 15-minute price for the balance of the hour decreases below the price specified by the market participant.

- **Dynamic transfer:** Market participants will continue to be able to establish dynamic transfer arrangements that enable 5-minute dispatch and settlement of intertie transactions. These will be settled similar to internal generation.

When determining the amount of fixed hourly schedules to accept on an intertie, the hour-ahead scheduling process will ensure it reserves intertie capacity for the maximum amount of variable energy resource schedules forecast for all 15-minute intervals in the hour. A penalty will apply if a variable energy resource routinely submits high forecasts to the hour-ahead process because these would displace other intertie resources. This penalty or the 5-minute price, depending on the circumstances, would also be applied to other intertie schedules that are not delivered.

Reinstatement of convergence bidding on the Interties

On November 28, 2011 the ISO suspended convergence bidding on the interties because of excessive settlement uplift charges attributable to convergence bidding on the interties. The market inefficiencies arose because convergence bid positions were closed-out at different prices -- intertie convergence bids were closed-out based on prices established by the hour-ahead scheduling process, while internal node convergence bids were closed-out at the 5-minute price.

As part of the real-time market changes to be made in conjunction with Order No. 764, Management proposes to close-out all convergence bids in the same market optimization. Both intertie and internal node convergence bids will be closed-out at 15-minute prices. This will eliminate the real-time imbalance energy offset settlement uplift charges attributable to intertie and internal node convergence bids closing-out at different prices.

The proposal will also address previous problems related to intertie convergence bids on the interties, in which physical export bids cleared the market at prices higher than their bid price. This problem occurred because the ISO enforced two constraints on each intertie: one that considered only physical intertie transactions, and a second that considered both physical and virtual intertie transactions. Management proposes to address this problem by only enforcing in the integrated forward market the constraint that considers both physical and virtual intertie transactions. This approach may result in physical schedules exceeding an intertie's capacity since a virtual schedule can provide counterflow to relieve congestion. Such an outcome is problematic in that the ISO must comply with a WECC requirement to only accept e-tags up to an intertie's capacity. To address this issue, Management proposes to accept e-tags in economic merit order of the cleared intertie bids up to an intertie's capacity. Any cleared intertie bids above that amount will not be allowed to e-tag prior to start of the real-time market.

Since virtual intertie schedules are only considered by the day-ahead market, and not the real-time market, the physical intertie schedules produced by the real time market will always be within each intertie's capacity. Consequently, the ISO will be able to accept e-tags for all intertie schedules by the real-time e-tag deadline of 20 minutes prior to the operating interval.

Many stakeholders continue to express concern about reinstating convergence bidding concurrent with the proposed design changes. The proposed real-time market changes constitute significant changes to the market, especially to the scheduling and pricing of intertie transactions. In addition, the ISO is planning to implement the Energy Imbalance Market in Fall 2014 which will expand the real-time market to include other balancing authorities. Therefore, Management proposes an initial twelve month period without intertie convergence bidding to allow the ISO and market participants to observe the operation of the new 15-minute market under various seasonal conditions. This is similar to the initial operation of the nodal market, in which there was an initial period without convergence bidding to allow the ISO and stakeholders to address any unanticipated market issues prior to adding the complexity of convergence bidding.

Management proposes to phase in convergence bidding on the interties through the use of "position limits," which limit the MW quantity of convergence bids that may be submitted by a scheduling coordinator to a percentage of the intertie transfer capability. Specifically, Management proposes the following schedule for phasing in convergence bidding on the interties:

Position Limit	**Schedule**
0%	15-minute market implementation to 12 months
5%	12 months to 20 months
25%	20 months to 24 months
50%	24 months to 28 months
No Limit	28 months

Participating Intermittent Resource Program (PIRP)

Order No. 764 provides an opportunity to create a market structure oriented around renewable resources. The addition of 15-minute schedules and settlement establish a market structure that is superior to the existing PIRP settlement provisions. Moreover, changes to the PIRP are required for it to be consistent with the new real-time market structure. The following outlines Management's proposed changes to PIRP under the new real-time market structure:

- Currently, the ISO schedules PIRP resources in the real-time market based on a forecast generated 90 minutes prior to the operating hour and fixed for the entire hour. This forecast output is settled at the average 5-minute price. Under Management's proposed changes to the real-time market, the ISO will create 15-minute schedules for PIRP resources based on forecasts generated 37.5 minutes prior to the 15-minute interval. This provides significant benefits. First, it provides for a 15-minute forecast to be scheduled in the market compared to the current hourly forecast. Second, the forecast lead time is shortened substantially and the forecast is updated four times per hour rather than once per hour. Finally, the 15-minute price should be less volatile than the 5-minute price

previously applied to the output forecast for the hour, greatly reducing variable energy resources' exposure to price volatility.

- Currently, PIRP resources' imbalances from hourly schedules are netted over the month and settled at the average monthly 5-minute price. This is appropriate in the current market to mitigate against real-time price risk because the imbalances from the hourly forecast can be significant.

  Under Management's proposal, the ISO will no longer net these imbalances over the month. PIRP resource imbalances will be substantially reduced under the new market structure as a result of being measured against the much more accurate forecast and granular 15-minute schedules. Management has used actual market data to compare the existing PIRP settlement provisions to those it proposes for the real-time market changes. The analysis shows that the vast majority of PIRP resources will receive more real-time market revenues under the new approach.

- Currently, the ISO does not have a market mechanism for dispatching PIRP resources down in the real-time market based on economic bids. Management's proposal includes the ability of PIRP resources to provide economic bids indicating their willingness to be curtailed in overgeneration conditions. This provides significant benefits to both the PIRP resources and the ISO's ability to maintain system reliability. By providing the ability for PIRP resources to submit economic bids, these resources can be paid to curtail output when needed to address system conditions.

  Submitting economic bids will also make PIRP resources eligible for bid cost recovery. Bid cost recovery shields PIRP resources from real-time price risk by guaranteeing the PIRP resource will not be charged an amount greater than its bid price for imbalance energy in the 5-minute dispatch.

To address ongoing operational issues, Management proposes to implement the economic bidding feature of PIRP in Fall 2013, earlier than the rest of the real-time market changes which Management plans to implement in Spring 2014. During this interim period (Fall 2013 to Spring 2014), in the intervals that the ISO dispatches a PIRP resource different from the PIRP forecast, the resource will not be eligible for the PIRP monthly netting of uninstructed imbalance energy for the applicable hour.

Management proposes to establish a process to identify existing PIRP resources that have operational characteristics or contractual limitations that require additional protective energy settlement measures under the proposed market design changes. This will further ensure that a PIRP resource is not significantly financially disadvantaged by the new real-time market structure and modifications to the existing PIRP settlement provisions. This process will be used to identify if there are any

impacted resources, so that protective measures can be developed that address the specific issues identified.

Management proposes that PIRP resources will have 30 days from the May Board of Governors meeting (June 14, 2013) to notify the ISO that they meet the specified criteria and request protective measures to address their operational characteristics. Management proposes that it would develop protective measures only if resources are identified that meet the criteria below:

1. A material portion of the existing plant's output uses technology that lacks the ability to receive and follow ISO curtailment dispatches or is contractually prohibited from curtailing output; and

2. The PIRP resource bears the imbalance market costs under its existing Power Purchase Agreement (PPA).

If protective measures are developed, they would remain in effect for the remainder of the resource's exiting PPA. Management also proposes to allow protective measures for a minimum of one year, if a resource's existing PPA expires between now and one year after implementation of the proposed market design changes to PIRP.

Based on data provided by the three investor-owned utilities, Management anticipates the number of resources meeting these criteria to be extremely limited and therefore believes it is best to address their particular circumstances on a case by case basis. If Management identifies any resources that meet the criteria above, it will commence a stakeholder process to develop any protective measures needed to address the operational characteristics of these resources.

POSITIONS OF THE PARTIES

Stakeholder input has generally recognized that the proposed design will help integrate variable energy resources, help to resolve existing issues with the pricing of intertie transactions, and address price volatility that currently exists in the 5-minute market. The following addresses the major concerns raised during the stakeholder process. A detailed stakeholder comment matrix is attached.

Issue 1: Management's proposal only to guarantee bid prices of intertie transactions on a 15-minute basis and not to guarantee the price for hourly schedules will conflict with the western bilateral energy market currently oriented around hourly energy and transmission purchases. This conflict could result in less liquidity and higher prices at the interties. As a result, market participants may engage in fewer real-time intertie transactions with the ISO and will incorporate a high risk premium into offers for hourly energy at the interties.

Response: The move to a 15-minute energy market over the interties is necessary to reliably integrate renewable resources and is consistent with Order No. 764. The

bilateral markets throughout the West will inevitably evolve to transact energy on a 15-minute basis to balance variable energy resources' schedule changes. The ISO's proposed approach accommodates hourly intertie schedules but creates economic incentives to bid energy on a 15-minute basis, which will provide a proper valuation of hourly and 15-minute intertie schedules.

Issue 2: Separately settling the 15-minute market schedules and the 5-minute real time dispatch may provide an incentive for resources to deviate from ISO dispatch instructions to arbitrage prices between the two markets. This could consist of an intertie transaction not delivering the amount dispatched in the 15-minute market or an internal generator deviating from its 5-minute real-time dispatch. A related concern is that a variable energy resource potentially could manipulate its forecast used for the 15-minute market to create differences with its 5-minute real time dispatch with commensurate profits.

Response: The respective market price appropriately values the cost of undelivered schedules. However, the ISO will monitor for deviations and propose deviation penalties in the future, if appropriate. In addition, the proposed market rules will allow the ISO to require a variable energy resource to use the ISO's forecast if a resource persistently submits forecasts with excessive error.

Issue 3: The ISO should maintain existing tariff provisions for variable energy resources participating in the participating intermittent resource program to net real time energy imbalances over the month.

Response: As described earlier, market participants will not need the netting provision under the new market design. First, variable energy resource forecasts will be generated 37.5 minutes prior to the start of the 15-minute market interval. In contrast, forecasts today are generated 90 minutes prior to the hour, which are flat for the entire hour. Second, variable energy resources will receive a financial position in real-time in the 15-minute market, which should have less volatile prices than the 5-minute prices in real time dispatch. Third, the ISO is proposing to establish a process to identify existing PIRP resources that have operational characteristics or contractual limitations that require additional protective energy settlement measures under the proposed market design changes. This process will be used to identify if there are any impacted resources, so that protective measures can be developed that address the specific issues identified.

Issue 4: The ISO's proposal to issue intertie dispatches for the 15-minute scheduling intervals at 22.5 minutes before the start of the interval, when updates to the energy portion of e-tags are due 20 minutes before the start of interval, will allow too little time, i.e. 2.5 minutes, for market participants to update the e-tags for schedule changes within the hour. A related concern is that some unforeseen sort of mechanical seams issue could arise with an adjacent balancing authority that does not accommodate 15-minute scheduling.

Response: In response to this specific concern, the ISO included a feature that will update e-tags by proposing an hourly option for the ISO to initiate intra-hour changes, which will expedite other balancing authority area's approval of the change. In addition, pursuant to WECC e-tagging rules, balancing authorities have an additional 10 to 15 minutes (depending on whether the change is at the top of an hour or within an hour) to confirm the e-tag changes before initiating the ramp for the schedule change. Discussions with neighboring balancing authorities confirm that they can accommodate 15-minute schedule changes.

The Market Surveillance Committee and the Department of Market Monitoring both support Management's proposal. The MSC's Final Opinion as well as a memo by the Department of Market Monitoring are attached for your reference.

CONCLUSION

Management respectfully requests Board approval of the FERC Order No. 764 market design changes as described in this memorandum. The proposed real-time market design enhancements will provide a market structure to effectively integrate a large amount of variable energy renewable resources within California and across the West and comply with FERC Order No. 764. The proposed design also effectively addresses observed market inefficiencies with the existing real-time market.

Attachment F – Draft Final Proposal on Protective Measures

Real-Time Market Design Enhancements Related to Order No. 764

California Independent System Operator Corporation

November 26, 2013

FERC Order 764 Market Changes

Intermittent Resource Protective Measures

Draft Final Proposal

August 15, 2013

Table of Contents

I. Introduction

The ISO Board of Governors approved the ISO's FERC Order No. 764 Market Changes proposal on May 15, 2013 that further prepares the ISO real-time market to better support the participation of intermittent resource in the ISO markets. The FERC Order No. 764 related changes proposed by the ISO provide a superior framework for scheduling intermittent resources in the real-time market, providing greater flexibility closer to real-time for such resources to limit their exposure to real-time energy imbalance changes associated with their uncontrollable variability. The new market structure significantly reduces the exposure to real-time imbalances thereby eliminating the need for the protection against exposure to hourly charges for uninstructed imbalance energy offered under the current Participating Intermittent Resource Program (PIRP).

Some owners of intermittent resources that do not have the ability to reduce their output maintain that these resources will have greater risk of undesirable real-time energy settlement under the new FERC Order No. 764 market structure. To address their concerns, this paper describes a proposal for "protective measures." These protective measures would enable resources that meet specified limited criteria to continue to be settled under the current PIRP monthly netting methodology for a maximum of three years.

The ISO's intent is that these protective measures would create a transition period for intermittent resources that face real-time market energy settlement risk that cannot be mitigated because they are unable to respond to ISO dispatch instructions to reduce output. This transition period would allow resource owners time to adapt to the new market. For example, they could upgrade intermittent resources based on older technology to current technology that is able to respond to ISO dispatch instructions, or they could develop different contractual arrangements with their counterparties.

The ISO proposes that these protective measures only last for a three-year transition period. While the ISO recognizes there is potentially a need for providing time for some resources to transition to the new market, it will be important for all resources to eventually transition to the new market design. As the ISO's FERC Order No. 764 market design changes recognize, it is vital that intermittent resources be able to reduce output during over-generation conditions. This is needed for the ISO to be able to integrate the large amounts of intermittent resources that need to come online to meet California's renewable resource goals.

The ISO will discuss the approach described in this paper with stakeholders as part of a stakeholder process and then present its final proposal to its Board of Governors at their September meeting. The schedule for the stakeholder process is described further below.

II. Changes to straw proposal

- Modified the "old technology" eligibility criteria to greater than 50% of the resource must be comprised of technology that is unable to curtail.

- The resource does not have the option to choose to be under the protective measurement settlement on an annual basis. Resources that select the protective measure settlement and are found to meet the eligibility criteria will be settled for the entire transition period based upon the protective measure.
- Resources must request protective measures within 30 days of the effective date of the FERC Order No. 764 market design tariff. The request and approval will be posted on the ISO website.
- The protective measure settlement will be in place for three years from the effective date of the FERC Order No. 764 market design tariff.

III. Background

The ISO's current market design provides for the real-time market to dispatch and settle energy in five-minute intervals at prices calculated for each five-minute interval. The current PIRP schedules and settles intermittent resources as follows:

- The resource self-schedules its forecast output for each hour in the real-time market at 90 minutes before the beginning of the hour. This self-scheduled amount is deemed to be instructed imbalance energy and is settled in each hour at the average five-minute locational marginal price (LMP).

- Deviations from these hourly forecasts are deemed to be uninstructed imbalance energy, are netted over each month, and the net deviation is settled at the output-weighted average of the five-minute LMPs.

Under the new FERC Order No. 764 market design, intermittent resources will be scheduled and settled as follows:

- Resources will be scheduled at their forecast output in 15-minute intervals at 37.5 minutes prior to the start of each interval. These forecast-based scheduled amounts will be settled in each 15-minute interval at 15-minute market LMPs.

- Deviations from these 15-minute forecasts and 5-minute dispatches will be instructed imbalance energy and will be settled at 5-minute market LMPs.

- Differences between the 5-minute dispatch and the metered energy will be uninstructed imbalance energy and will be settled at 5-minute market LMPs.

- The new market design also provides for intermittent resources to submit economic energy bids so that a resource can be dispatched to a level less than its maximum forecast output in either the 15-minute or 5-minute market if the LMP is less than the resource's bid. This feature will be important when prices are negative due to system over-generation conditions because under these conditions the ISO market will charge a resource for its energy production.

The ISO analyzed the effect of the FERC Order No. 764 methodology on intermittent resources as compared to the PIRP settlement under the current market. This is summarized in the Figure 1 below that compares the settlement for six current PIRP resources.

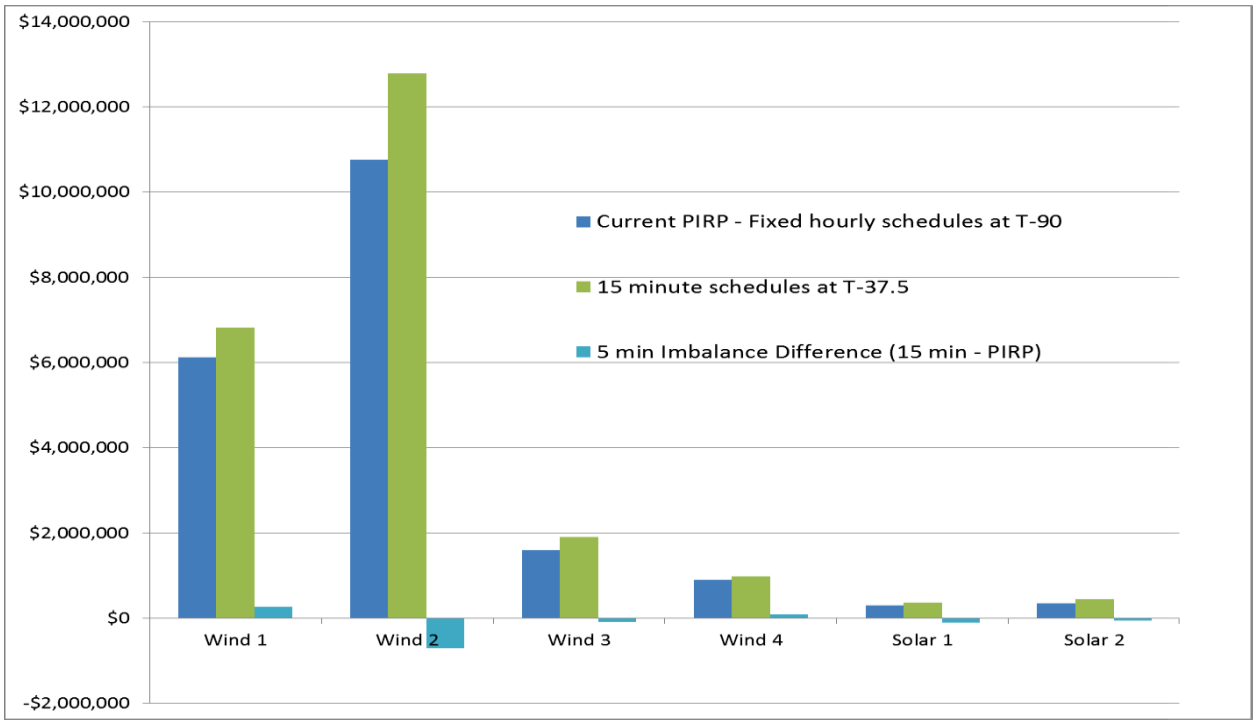

Figure 1 - Real-time Market Revenue Comparison (July 2011 – June 2012) using persistence as a proxy for 15-minute forecast

As Figure 1 shows, intermittent resources generally will be paid more in the real-time market under the FERC Order No. 764 market design than under the current market design and PIRP settlement. This is because:

- A large portion of the resources' output will be settled in the 15-minute market using a more accurate and granular forecast than that used to establish hourly schedules under the existing PIRP.
- Unlike the hourly schedule under the existing PIRP that is priced using the 5-minute LMPs to calculate the average hourly price, 15-minute schedules will be priced at the 15-minute LMP.
- These 15-minute LMPs will be less volatile and less likely to be negative than 5-minute LMPs. In addition, only a relatively small quantity of energy will be settled at 5-minute LMPs under the new market design.

Finally, the settlement under the FERC Order No. 764 market should be much more advantageous than shown in Figure 1 because:

- Figure 1 was created using a forecast that was merely a resource's output at 37.5 minutes prior to the interval. An actual forecast would predict the change in the resources output that will occur in the upcoming 37.5 minutes.

- Figure 1 assumes no ability to respond to dispatch instructions. Consequently, the chart shows resources will be paid more in the real-time market under the FERC Order No. 764 market changes even without the ability to respond to dispatch instructions.

When the ISO Board of Governors approved the FERC Order No. 764 market design during its May 2013 meeting, some resource owners maintained that their resources would be disadvantaged under the new market design because their intermittent resources lacked the ability to respond to dispatch instructions to produce less energy than its forecast maximum output. The ISO Board of Governors directed ISO management to investigate whether limited protective measures for intermittent resources are appropriate, and to make a recommendation at the September 2013 Board of Governors meeting. If the protective measures are approved by the Board of Governors, the protective measures will be submitted to FERC as part of the ISO's FERC Order No. 764 proposal to be filed in November 2013.

Subsequently, the ISO issued market notices on May 16, 2013 and May 30, 2013 requesting information regarding intermittent resources for which market participants were considering requesting protective measures. The ISO received information from 24 market participants for resources accounting for approximately 2,000 MW of capacity. The ISO then had discussions with those market participants to understand the characteristics of these resources and the terms of any bilateral contracts these resources had for their output. The information gained during these discussions led to the ISO's proposal for protective measures described in this paper.

IV. Proposed Protective Measures

This section describes the proposed protective measures for qualifying intermittent resources under the initial operation of the ISO's new FERC Order No. 764 market design.

Qualifying Criteria

As described above, the proposed FERC Order No. 764 market design provides a superior framework for scheduling intermittent resources and provides incentives for intermittent resources to reduce their output in response to grid conditions as signaled by market prices. This response is vital to the ability of the ISO to integrate the large amounts of intermittent resource needed to meet California's environmental goals. Consequently, to not unduly undermine these incentives, and to only address situations in which a market participant would be unduly burdened during the transition to the new market design, the proposal is that only resources that meet the following limited criteria would be eligible for the protective measures:

1. Greater than 50% of the resource is composed of old technology that is unable to curtail output without significant investment.

- Dispatch, control, and telemetry or metering needs only would not qualify
- Turbine replacement would qualify

2. There are not options under a bilateral contract to mitigate real-time energy settlement risk.
    - Qualifying Facilities (QFs) 20 MW or less are not eligible.
    - Any bilateral contract (i.e. PPA) must specify resource is directly or indirectly responsible for costs based on ISO market real-time energy settlement.
3. During the term of the transition period, the resource owner will seek a long-term PPA and/or will upgrade the intermittent generator so that it can respond to ISO dispatch instructions.
4. The resource owner must sign an affidavit certifying the resource meets all criteria (items 1 thorough 3) above.

The ISO proposes to limit the protective measures to resources with greater than 50% older technology for which the underlying design of the resource prevents it from responding to ISO dispatches. The ISO believes that it would potentially unduly burden resource owners to have to immediately make improvements such as replacing turbines. However, extending protective measures to resources that merely need to install dispatch, control, or telemetry systems would undermine the incentive to respond to dispatch instructions that the FERC Order No. 764 market design is intended to provide. The ISO does not believe that these more moderate upgrades will be unduly burdensome.

The ISO proposes to limit the protective measures to resources that do not have options under a bilateral contract to mitigate the risk of adverse settlement of energy in the ISO real-time market. QFs with a maximum output less than or equal to 20 MW would not qualify for protective measures because these resources are eligible to enter into a contract with a CPUC-regulated investor-owned utility that will provide protection from adverse energy settlement in the ISO's market.[1] Resources that are not responsible for costs based on ISO market real-time energy settlement would not be eligible for protective measures as they would not be affected by the market design changes.

Protective Measure Settlement

The ISO proposes the protective measures consist of a real-time market settlement that is the same as the existing settlement under PIRP.

[1] In December 2010, the California Public Utility Commission (CPUC) issued an order approving a global settlement agreement between the investor-owned utilities, CHP resources, ratepayer advocates, and the CPUC staff over a number of qualifying facility and combined heat and power to settle a number of issues outstanding in various CPUC proceedings, which included retention of mandatory purchases from QF facilities 20 MWs or less. (D.10-12-035)

PIRP requires the resource to provide meteorological data in order for the ISO's forecast service provider to develop a resource specific forecast. QFs currently do not provide meteorological data; therefore, when their QF contract expires, in order to request protective measures, the resource must complete the PIRP certification process, including the ability to provide meteorological data, so that the existing settlement under PIRP can be calculated. Only after the PIRP certification process is completed will a QF resource be settled according to the existing PIRP method.

Specifically, a resource under the protective measure would be settled as follows:

- An hourly schedule will be set using a 90 minute in advance forecast.
- The resource's hourly schedule based on its 90-minute in advance forecast will be settled at the simple average of the 5-minute LMPs.
- The deviations between the resource's actual energy output and the hourly schedule will be netted over each month. This amount will be settled at the output-weighted average of 5-minute LMPs over the month.

Some parties have argued that the protective measures should consist of the resource receiving the FERC Order No. 764 market 15-minute settlement, with deviations from the 15-minute schedules netted over the month. The ISO does not believe this would be appropriate as a protective measure, as it would undermine incentives for resource owners to upgrade resources so that they are dispatchable rather than depend on protective measures.

Protective Measure Settlement Allocation

The difference between the real-time market settlement of any resource under the protective measure and the settlement that would have occurred under the FERC Order No. 764 market design will be allocated to in the same manner as the existing PIRP settlement, which is to net negative deviations. This amount may be a payment or a cost to net negative deviations.

The ISO had previously stated that it was considering allocating the protective measure settlement amounts to the load serving entity with a PPA with the resource. The ISO has determined that allocation to net negative deviations is more appropriate because (1) resources that are eligible for protective measures may be resources coming off QF contracts that do not have a PPA with a load serving entity, and (2) the resource requesting the protective measure may be responsible for costs based on ISO market real-time energy settlement, but the load serving entity with the PPA with the resource may be the scheduling coordinator for the resource. Since the ISO settles market transactions with scheduling coordinators, if the costs of the protective measure were allocated to the load serving entity under the circumstances described in (2), then the costs of the protective measure would be allocated to the same scheduling coordinator that would be receiving the protective measure.

The protective measures and cost allocation add to the complexity and costs of implementing the Order No. 764 changes. Because of the need to comply with FERC's Order No. 764 in a

reasonably timely manner, the ISO cannot delay the implementation of the market design changes that are necessary to accommodate the 15-minute scheduling required by the Commission's order. Therefore, while the ISO will strive to provide these financial adjustments soon after the start of the new market, the resource's settlement will be trued up in later settlements after go live. Any adjustments will be subject to the FERC interest rate, as already provided in the ISO tariff.

Duration of Protective Measures

The ISO proposes that the duration of the protective measures will be three years from the effective date of the tariff provisions implementing the Order No. 764 market design changes or until a new PPA is signed for the resource, whichever comes first. The intent of the protective measures is to provide a transition period for a resource meeting the criteria for a protective measures to be able to adapt to the new market, such as developing the capability to respond to dispatch instructions.

Process to Request Protective Measures

The ISO proposes that resources, meeting all eligibility requirements above, must request protective measures within 30 days of the effective date of FERC Order No. 764 market design changes. If a resource will meet the eligibility requirements within the three year transition period, the resource must provide the date that resource meets the eligibility requirement and also request protective measures within the 30 days of the effective date of FERC Order No. 764 market design changes.

The ISO will post on its website the requests received and the disposition of the requests.

V. Next Steps

The schedule for the stakeholder process to finalize the protective measure is as follows.

Date	Event
August 15, 2013	Draft Final Proposal Posted
August 22, 2013	Stakeholder Call
August 29, 2013	Stakeholder Comments Due on Draft Final Proposal
September 12, 2013	Present proposal for decision at September Board of Governors Meeting

The ISO will discuss this draft final proposal with stakeholders during a call to be held on August 22, 2013. Stakeholders should submit written comments by August 29, 2013 to Order764@caiso.com.

Attachment G – September 5, 2013 Board Memorandum

Real-Time Market Design Enhancements Related to Order No. 764

California Independent System Operator Corporation

November 26, 2013

Memorandum

To: ISO Board of Governors

From: Keith Casey, Vice President, Market & Infrastructure Development

Date: September 5, 2013

Re: **Decision on FERC Order No. 764 market changes intermittent resource transitional protective measure**

This memorandum requires Board action.

EXECUTIVE SUMMARY

The ISO Board of Governors approved the ISO's FERC Order No. 764 Market Changes proposal on May 15, 2013. The proposed market design enhancements orient the ISO real-time market to better support the participation of intermittent resources. The new real-time market design will provide a superior framework for scheduling intermittent resources and limit their exposure to real-time energy imbalance changes associated with their uncontrollable variability. As a result, the need for the protection against exposure to hourly charges for uninstructed imbalance energy offered under the current participating intermittent resource program is largely eliminated.

At the May 2013 Board meeting, some resource owners maintained that they could be disadvantaged under the new market design because of their inability to respond to dispatch instructions. In response, the Board directed Management to investigate whether limited protective measures for intermittent resources are appropriate, and to make a recommendation at the September 2013 Board meeting. Management is proposing a limited protection measure as described in the memorandum to provide older technology renewable resources a three year transition period so that they can effectively operate under the new market structure. The transition period will provide time for resources that may be unduly burdened by the new market structure to negotiate any necessary changes to their power purchase agreements or in the case of qualifying facilities that will be rolling off of their current PURPA contract, to enter into new purchase power agreements to manage their imbalance energy price risk.

Management proposes the following motion:

> ***Moved, that the ISO Board of Governors approves the proposed intermittent resource transitional protective measure, as described in the memorandum dated September 5, 2013; and***

Moved, that the ISO Board of Governors authorizes Management to make all necessary and appropriate filings with the Federal Energy Regulatory Commission to implement the proposed tariff change.

DISCUSSION AND ANALYSIS

Background

Under the current participating intermittent resource program (PIRP), intermittent resources are scheduled and settled as follows:

- A PIRP resource self-schedules its forecast output for each hour in the real-time market at 90 minutes before the beginning of the hour. This self-scheduled amount is deemed to be instructed imbalance energy and is settled in each hour at the average 5-minute locational marginal price (LMP).

- Deviations from these hourly forecasts are deemed to be uninstructed imbalance energy, are netted over each month, and the net deviation is settled at the output-weighted average of the 5-minute LMPs.

Under the new FERC Order No. 764 market design, intermittent resources will be scheduled and settled as follows:

- Resources will be scheduled at their forecast output in 15-minute intervals at 37.5 minutes prior to the start of each interval. These forecast-based scheduled amounts will be settled in each 15-minute interval at 15-minute market LMPs.

- Deviations from these 15-minute forecasts and 5-minute dispatches will be instructed imbalance energy and will be settled at 5-minute market LMPs.

- Differences between the 5-minute dispatch and the metered energy will be uninstructed imbalance energy and will be settled at 5-minute market LMPs.

- The new market design also provides for intermittent resources to submit economic energy bids so that a resource can be dispatched to a level less than its maximum forecast output in either the 15-minute or 5-minute market if the LMP is less than the resource's bid. This feature will be important when prices are negative due to system over-generation conditions because under these conditions resources are charged for their energy production.

Some resource owners maintain that their resources would be disadvantaged under the new market design because they lack the ability to respond to dispatch instructions. However, this concern is largely addressed under the new market structure by scheduling these resources closer to the operating hour at a 15 minute granularity. This significantly reduces these resources' exposure to 5-minute prices and cost allocations to uninstructed imbalance energy.

To gauge the potential impact of the new market design on non-dispatchable wind and solar resources, Management analyzed the settlement effect of the FERC Order No. 764 settlement on a sampling of resources and compared this to the PIRP settlement under the current market. The analysis shows that these resources generally will earn more revenue in the real-time market under the new market design than under the current market design including PIRP settlement.[1]

Proposed protective measure

Although most intermittent resources should be better off under the new market structure, Management proposes that certain resources have the option of selecting a transitional protective measure that consists of a real-time market settlement that is similar to the existing settlement under PIRP. Specifically, a resource under the proposed protective measure would be settled as follows:

- An hourly schedule will be set using a 90-minute in advance forecast.
- The resource's hourly schedule based on its 90-minute in advance forecast will be settled at the simple average of the 5-minute LMPs.
- The deviations between the resource's actual energy output and the hourly schedule will be netted over each month. This amount will be settled at the output-weighted average of 5-minute LMPs over the month.

As under the current PIRP rules, resources under the transitional protective measure settlement would be required to provide meteorological data for the independent forecast service provider to develop a resource-specific forecast. Therefore, qualifying facilities that currently do not provide meteorological data would be required to complete the PIRP certification process to be settled under the protective measure upon expiration of their contract. Only after the PIRP certification process is completed will a resource be settled according to the proposed protective measure.

Qualifying criteria

As described above, the proposed FERC Order No. 764 market design provides a superior framework for scheduling intermittent resources and provides incentives for intermittent resources to reduce their output in response to grid conditions as signaled by market prices. This response is vital to the ISO's ability to integrate the large amounts of intermittent resources needed to meet California's environmental goals.

[1] During the stakeholder initiative the ISO analyzed six representative resources; the analysis is available at http://www.caiso.com/Documents/Web%20conference%20May%201,%202013. In addition, the ISO has provided this analysis for additional resources at the request of the resource and its load serving entity counterparty.

Consequently, to not undermine these incentives, and to address only situations in which a market participant would be unduly burdened during the transition to the new market design, the proposal is that only resources that meet the following limited criteria would be eligible for the transitional protective measure:

1. More than 50% of the resource is composed of old technology that is unable to curtail output without significant investment.

    - Dispatch, control, and telemetry or metering needs only would not qualify

    - Turbine replacement would qualify

2. Resource is responsible for real-time energy settlement under their current power purchase agreement (PPA).

    - Qualifying facilities 20 MW or less are not eligible because they can enter into new standard offer agreements insulating them from imbalance energy settlement.

    - Any bilateral contract (i.e. PPA) must specify that the resource is directly or indirectly responsible for costs based on ISO market real-time energy settlement.

3. During the term of the transition period, the resource owner agrees to seek modifications to their power purchase agreement or a new power purchase agreement that address their imbalance energy settlement and/or will take steps to upgrade the resource so that it can respond to ISO dispatch instructions.

4. The resource owner must sign an affidavit certifying the resource meets all criteria (items 1 thorough 3) above.

Duration

Management proposes the duration of the transitional protective measure will be three years from the effective date of the tariff provisions implementing the FERC Order No. 764 market design changes or until a new PPA is signed for the resource, whichever comes first.

Allocation of Protective Measure Costs and Revenues

The difference between the real-time market settlement of any resource under the protective measure and the settlement that would have occurred under the FERC Order No. 764 market design will be allocated in the same manner as the existing PIRP settlement, which is to net negative deviations. This amount may be a payment or a cost to net negative deviations.

The protective measure and cost allocation add to the complexity and costs of implementing the FERC Order No. 764 market design changes. Because of the need to

comply with FERC Order No. 764 in a reasonably timely manner, the ISO cannot delay the implementation of the market design changes that are necessary to accommodate the 15-minute scheduling required by the Commission's order. Therefore, while the ISO will strive to provide these financial adjustments soon after the start of the new market, the resource's settlement will be trued up in later settlements after go live. Any adjustments will be subject to the FERC interest rate, as already provided in the ISO tariff.

Process to seek approval of protective measure

Management proposes that resources, meeting all eligibility requirements above, must request transitional protective measures within 30 days of the effective date of FERC Order No. 764 market design changes. If a resource will meet the eligibility requirements within the three year transition period, the resource must provide the date that resource meets the eligibility requirement and also request protective measures within the 30 days of the effective date of FERC Order No. 764 market design changes. Resources that qualify and select the protective measure settlement must remain under that settlement for the entire three year transition period or until they enter into a new power purchase agreement, whichever comes first. Management will post on its website the requests received and the disposition of the requests.

POSITIONS OF THE PARTIES

Stakeholders remain divided on the appropriateness of providing a protective measure to older technology intermittent resources, the proposed scope of the protective measures, and the cost allocation.

CalWEA argues that the proposed protective measures will be ineffective in addressing older technology intermittent resources' exposure to FERC Order No. 764 market design changes. They are concerned that the eligibility requirements are unduly restrictive and the duration undermines the utility of the protective measure.

Load serving entities question the need for the protective measure given that the FERC Order No. 764 market design changes were develop to facilitate the integration of variable energy resources. Load serving entities support a firm expiration date, limiting the program to resources physically unable to follow dispatches, and allowing eligible resources to fully opt-in or opt-out of the protective measure. However, they remain opposed to the cost allocation, expanding eligibility to resources that do not have a contract with a load serving entity and allowing another request window.

CONCLUSION

Management respectfully requests Board approval of the intermittent resource transitional protective measure as described in this memorandum. The protective measure will provide a transition period for a resource meeting the criteria to be able to adapt to the new market, either contractually or by developing the capability to respond to dispatch instructions.

Attachment H – DMM Memorandum

Real-Time Market Design Enhancements Related to Order No. 764

California Independent System Operator Corporation

November 26, 2013

Memorandum

To: ISO Board of Governors

From: Eric Hildebrandt, Director, Market Monitoring

Date: May 8**,** 2013

Re: **FERC Order No. 764 Market Design Changes**

This memorandum does not require Board action.

EXECUTIVE SUMMARY

The Department of Market Monitoring (DMM) strongly supports Management's proposed market design changes stemming from FERC Order No. 764. As described in Management's memo on this topic, these market design changes are designed to more effectively and efficiently integrate larger amounts of renewable variable energy resources into the ISO system.

A key feature of these changes is the establishment of financially binding 15-minute energy schedules and prices for all resources, including those within the ISO systems as well as imports and exports on interties with other balancing areas. DMM expects this to increase market efficiency by creating price signals that more closely reflect the value of intertie schedules that can be changed over the operating hour and provides an incentive for more resources to transition to providing 15-minute scheduling flexibility. Settling internal and intertie schedules (including virtual bids) at 15-minute market prices will also help to significantly reduce real-time energy imbalance offset charges.

DMM worked closely with the ISO and stakeholders in developing these market design changes. Management's final proposal includes several key modifications made to address concerns identified by DMM. While Management's proposed changes will greatly enhance market performance, DMM cautions that large real-time revenue imbalances could still accrue when real-time congestion occurs and transmission limits are adjusted downward after the day-ahead market to account for unscheduled flows. Thus, it will remain important for the ISO to continue efforts to improve modeling of power flows, so that the need to reduce flows in real-time by adjusting constraint limits downward is reduced.

BACKGROUND

In June 2012, FERC approved Order No. 764, which is designed to remove barriers to the integration of variable energy resources by requiring every transmission provider to allow adjustment of energy schedules between balancing areas every 15 minutes, rather than allowing only hourly scheduling on interties. The ISO views Order No. 764 as an opportunity to implement real-time market changes that were not possible before this order. These changes include establishment of a 15-minute market for scheduling and settlement of all resources, including those within the ISO, as well as imports and exports on interties with other balancing areas. Establishing this type of 15-minute market allows the ISO to address some of the fundamental market inefficiencies that led to high real-time energy imbalance offset costs and the suspension of virtual bidding on interties in December 2011.

Management's final proposal includes several key modifications made to address concerns identified by DMM. We strongly support Management's proposed changes and expect them to more effectively and efficiently integrate larger amounts of renewable variable energy resources into the ISO system, while enhancing overall real-time market performance and efficiency. The remaining sections of this memo provide DMM's comments on the main benefits and components of Management's proposed changes.

HOURLY INTERTIE SCHEDULES

We strongly support the portion of the ISO proposal regarding settlement of hourly intertie schedules that are not dispatchable on a 15-minute basis. Under the ISO proposal, imports and exports have the option of continuing to be bid and scheduled on a fixed hourly basis as part of an hour-ahead scheduling process. These bids are also referred to as *hourly block* resources, since if these bids are accepted they must be scheduled at the same fixed quantity for the entire operating hour. Fixed hourly schedules resulting from this process will be settled based on prices that are determined through the dispatch process that is performed every 15 minutes throughout the operating hour. Bid cost recovery will not be paid if these 15-minute prices fail to cover the bid price of fixed hourly transactions.

DMM strongly supports this approach since it creates appropriate price signals that more closely reflect the different value of fixed hourly-block schedules relative to flexible interties schedules that can adjusted on a 15-minute basis. This also provides an incentive for more suppliers to transition to providing 15-minute scheduling flexibility. We believe this is important to help achieve the long-term goal of these market design changes of more effectively and efficiently integrating larger amounts of renewable variable energy resources into the ISO system.

Under the ISO's proposal, hourly block schedules can incorporate the risk of 15-minute market prices exceeding their costs into their hourly bid prices. Bids for hourly block imports will be exposed to the risk of 15-minute market prices settling below the hourly block advisory price. These incremental imports can raise their bid price in order to hedge themselves against this risk.

As noted in the MSC's opinion, while the introduction of 15-minute scheduling without price guarantees for fixed hourly schedules represents a significant operational and market change, experience at other ISOs and RTOs indicates that these changes can be effectively managed by market participants and the ISO. These same market features have been in place at the PJM and the Midwest ISO for around 8 years. Therefore, DMM also believes that these market features can be successfully implemented in California. However, DMM concurs with the MSC that the impacts of these changes will need to be analyzed by the ISO following implementation.

Finally, DMM has noted that providing bid cost recovery for imports and exports would essentially re-instate the same "bid or better" settlement rules for hourly intertie schedules that led to over $33 million in uplift cost from the time these rules were implemented on October 1, 2004 until the time they were changed on March 25, 2005 through the filing of Amendment 66 to the ISO tariff.[1] As explained in the ISO's Amendment 66 filing, these uplifts inevitably result when real-time prices are either higher or lower than the projected or advisory prices used to clear the hour-ahead market. A very large portion of this uplift was paid for off-setting import and export bids (by the same or different participants) that provided no net energy to the ISO system.

REAL-TIME IMBALANCE OFFSET COSTS

The real-time imbalance offset charge is the difference between the total money paid out by the ISO and the total money collected by the ISO for energy settled at hour-ahead and 5-minute market prices. In the past, high real-time energy imbalance offset charges have resulted when large volumes of energy on interties have been bought back in the hour-ahead market at relatively low prices, and then replaced by purchases of additional energy from resources within the ISO system in the 5-minute real-time market at higher prices. These revenue imbalances are allocated to load-serving entities based on measured demand.

Under the proposed changes, most real-time transactions on interties and resources within the ISO will be scheduled and settled based on the same 15-minute market process. This should significantly reduce revenue imbalances allocated through real-time energy imbalance offset charges by essentially eliminating the difference in prices

[1] See Amendment 66 tariff filing, March 23.2005, available on ISO website at: http://www.caiso.com/Documents/Req_ExpeditedConsideration_ShortenedCommPeriod.pdf

used to settle intertie transactions and 5-minute prices currently used to settle energy from resources within the ISO.

However, high real-time imbalance offset charges can also result from differences in congestion prices and flows on interties between the day-ahead and real-time markets. Thus, despite the proposed market improvements, large real-time revenue imbalances could still occur if transmission limits are adjusted downward after the day-ahead market to account for unscheduled flows when congestion occurs. This creates offset costs by reducing the volume of energy flows in the real-time market over congested constraints. It will remain therefore important for the ISO to continue efforts to improve modeling of flows in these two markets, so that the need to reduce flows in real-time by adjusting constraint limits downward is reduced.

VIRTUAL BIDDING

The ISO is proposing to re-implement virtual bidding on interties 12 months after these market design changes are implemented. DMM believes this is a prudent approach given the significant nature of the market design changes being proposed and the past experience with virtual bidding in the ISO market.

Under Management's proposal, when virtual bidding on interties resumes, all virtual bids on interties and internal locations within the ISO will all be settled at the 15-minute prices. This eliminates the problem that led to high real-time energy revenue imbalance costs and the suspension of virtual bidding on inter-ties in late 2011.[2]

However, DMM cautions that virtual bidding on interties could still inflate uplift cost from real-time revenue imbalances that stem from differences in congestion and flows on interties between the day-ahead and real-time markets. As discussed in DMM's 2012 annual report, this occurs when constraint limits need to be adjusted downward in the real-time market to account for unscheduled flows not incorporated in the day-ahead market model. Thus, DMM has recommended the ISO carefully consider this issue and that if virtual bidding on interties is re-implemented this be done in a very limited and gradual manner that is contingent on the observed performance of this new market design.

SCHEDULING OF VARIABLE ENERGY RESOURCES

The proposed changes allow variable energy resources to reserve hourly intertie transmission capacity to accommodate fluctuations in these resources' 15-minute

[2] As described in DMM's 2011 annual report, this problem was created by the fact that virtual bids at inter-ties were settled on hour-ahead prices, while virtual bids at internal locations were settled at 5-minute prices. For further detail see the *2011 Annual Report on Market Issues and Performance*, Department of Market Monitoring, April 2012, pp. 77-79: http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf.

schedules. This represents a key provision of the proposal aimed at removing barriers to the integration of variable energy resources.

Hourly transmission capacity reserved for variable energy resources will either become financially binding or released for other resources in the 15-minute market. However, this has the potential to allow transmission reservations for variable energy resources to displace intertie resources with fixed hourly schedules. Consequently, DMM has recommended that the ISO retain the authority to utilize its own forecast of the output of a variable energy resource if schedules submitted by these resources appear to be systematically inaccurate and create detrimental market impacts.

CONCLUSION

DMM strongly supports Management's proposed market design changes stemming from FERC Order No. 764. These market design changes should help to more effectively and efficiently integrate larger amounts of renewable variable energy resources into the ISO system. DMM worked closely with the ISO and stakeholders in developing these market design changes. Management's final proposal includes several key modifications made to address concerns identified by DMM. As with any major market design change, it remains important to continually monitor and reassess the effectiveness of these market design changes as they are implemented and adjust rules as needed in response to actual market performance.

Attachment I – MSC Opinion

Real-Time Market Design Enhancements Related to Order No. 764

California Independent System Operator Corporation

November 26, 2013

Opinion on
Order 764 Compliance and Related Market Design Changes

by

James Bushnell, Member
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Members of the Market Surveillance Committee of the California ISO

Final of May 7, 2013

1. Introduction

The Market Surveillance Committee (MSC) of the California Independent System Operator has been asked to provide an opinion on the ISO's proposal for complying with FERC Order 764 and related market design changes.[1] Order 764 requires that jurisdictional transmission providers allow interchange to be scheduled on a 15 minute basis, and that variable energy resources provide data to market operators for the purpose of forecasting power output. The ability to schedule on a 15 minute basis would potentially reduce the burden on balancing authority areas (BAAs) that are the source of intermittent resource output and shift this burden to the destination or sink BAAs. The ISO's proposal to comply with the Order would implement full 15 minute energy scheduling and settlements.

The proposed changes have three main threads, two of which have been the subject of prior stakeholder processes and MSC opinions. The first thread is the California ISO's compliance with FERC Order 764, particularly its requirement that jurisdictional utilities allow 15 minute scheduling of interchange transactions. The second thread consists of associated changes to the way the California ISO prices interchange transactions, which has been the subject of multiple stakeholder processes over the past two years and was discussed in our August 16, 2011 opinion.[2] Significantly, the changes proposed by the California ISO would extend beyond the pricing of interchange transactions with external BAAs to also change the way internal generation and load are settled. The third thread is comprised of changes to the Participating Intermittent Resource Program (PIRP) program that would serve to align the design of the PIRP program with the new elements of the California ISO market and allow PIRP resources to

[1] California ISO, *FERC Order 764 Compliance, 15-Minute Scheduling and Settlement*, Draft Final Proposal, March 26, 2013, www.caiso.com/Documents/DraftFinalProposal-FERC-Order764MarketChanges.pdf

[2] Market Surveillance Committee of the California ISO, Final Opinion on Intertie Convergence Bidding and the Imbalance Energy Offset, August 16, 2011, www.caiso.com/Documents/FinalOpinion_IntertieConvergenceBidding_ImbalanceEnergyOffset.pdf

participate in the economic dispatch. We discussed some of these changes in our prior December 8, 2011 opinion.[3]

More recently, potential changes to the way the California ISO settles interchange transactions have been discussed in several MSC meetings over the past two years, and these specific changes were discussed in MSC meetings in Folsom on January 17, 2013, and March 19, 2013. In addition, MSC members have participated in stakeholder calls discussing Order 764 compliance and these associated changes on October 30, 2012, December 18, 2012, February 12, 2013, April 2, 2013, and May 1, 2013.

The Order 764 proposal is relatively complicated, and although stakeholders generally agree the proposal makes beneficial market changes, some features have raised concerns among stakeholders. In this opinion, we focus on the above three main elements of the proposed market changes.

Our overall recommendation is that we support those three elements. The introduction of 15 minute energy scheduling is not only necessary to comply with FERC Order 764, it also offers the potential to improve the performance of California ISO markets (and indeed markets throughout the West) and reduce the cost of meeting load by enabling more optimal scheduling of interchange with adjacent BAAs. Extending the present real-time pre-dispatch (RTPD) process to include energy scheduling and settlements in addition to its present unit commitment and operating reserve roles has the potential to significantly improve the consistency of the ISO's markets.[4] Importantly, the associated changes in the settlement of interchange transactions and virtual bids (in which they are based on binding 15-minute/RTPD market prices) should allow interchange to be settled at prices that are better aligned with real-time prices than is the case with the present HASP-based settlement process for interchange transactions. Finally, we anticipate that scheduling interchanges involving intermittent resources closer to real-time and allowing internal and external intermittent resources to be dispatched based on price will have several benefits. In particular, this element of the proposal should improve the California ISO's ability to balance load and generation in real-time with reduced price volatility; enable external variable energy resources to supply power to California at lower cost; and allow internal variable energy resources to participate more efficiently in the real-time market.

[3] Market Surveillance Committee of the California ISO, Opinion on Integration; Market and Product Review, Phase I, December 8, 2011, www.caiso.com/Documents/ MSC_Final_Opinion_RenewableIntegrationMarket-ProductReviewPhase1.pdf

[4]The name of the present 15-minute process--"Real time pre-dispatch" (RTPD)--will therefore become something of a misnomer under this proposal, because the revised 15 minute scheduling software will both commit and dispatch generation, and yield financially binding market prices for both ancillary services and energy for the first 15 minute interval. Presently, under MRTU, energy schedules from RTPD are not binding financially, so "pre-dispatch" was a more appropriate description in that case. Nonetheless, under the ISO's proposal, the 15 minute process will remain advisory for the second and subsequent intervals, and so would still be a predispatch evaluation which has a purpose of informing commitment decisions.

There are some risks associated with the implementation of these changes that will need to be analyzed by the California ISO as this design moves toward implementation, as well as monitored following implementation.

- First, it cannot be assumed that there will necessarily be a liquid supply of 15 minute interchange bids and offers when this design is first implemented. Uncertainty concerning the impact of implementing these changes could lead to somewhat higher offer prices for import supplies scheduled in real-time. Further, the overall elasticity of import supply in real-time, both hourly and 15 minute transactions, may initially be somewhat lower than under the current design, but there will be offsetting benefits in the form of reduced costs from uneconomic import and export transactions.[5]

- Second, while settling interchange transactions at RTPD prices determined closer to real-time should tend to reduce uplift costs (real-time energy offset costs), settling internal generation and load deviations from day-ahead schedules at RTPD prices and then settling deviations from RTPD schedules at RTD prices will give rise to new uplift costs. We anticipate that the net effect of these changes will likely be a reduction in overall uplift costs relative to the current design. Nonetheless, the California ISO will need to carefully monitor the relationship between RTPD solutions and the real-time dispatch to minimize both systematic errors and large random errors in order to achieve the intended benefits of these design changes.

- Third, if the supply of 15 minute interchange bids and offers is initially not very liquid, the elements of the design that allow output-contingent intermittent offers to displace fixed hourly import schedules may contribute to the volatility of RTPD and RTD prices. This potential can be studied prior to implementation and managed by the way the California ISO forecasts variable resource output for the HASP process.

While the introduction of 15 minute scheduling will pose some operational challenges for the California ISO and adjacent control areas, experience at other ISOs and RTOs indicates that these challenges should not be unmanageable. PJM has been allowing 15 minute changes of price-taking interchange transactions with some adjacent control areas for more than a decade, and the Midwest ISO and PJM have been managing large volumes of price-taking 15 minute schedule changes for around 8 years. Moreover, the New York ISO implemented price-based scheduling of 15 minute transactions with Hydro Quebec in 2011 and with PJM in 2012. Hence, the California ISO is not entering uncharted waters in implementing 15 minute scheduling; this is something that other ISOs and RTOs have been able to manage and the California ISO should be able to successfully implement if given flexibility in the timing and manner of implementation.

The remainder of this opinion is organized as follows. The next section summarizes some economic principles underlying our assessment of this proposal. Section 3 reviews the salient

[5] There has generally been a reduction in imports into the California ISO in real-time in recent years (day-ahead net imports are larger than real-time net imports), although this relationship varies from hour to hour and day to day, see California ISO, Department of Market Monitoring, 2012 Annual Report on Market Issues and Performance, Figure 2.8, p. 67

features of the most recent CAISO proposal, and offers some observations on those features. Our recommendations are presented in Section 4.

2. Economic Principles

The following principles of design of economically efficient electricity markets underlie our assessment of the ISO's proposal.

- Smaller intervals for scheduling will result in increased flexibility of interchange schedules, and allow better matching of supply and demand.

- Settling internal, external, and virtual transactions with the same set of RTPD prices will eliminate the potential for market participant bidding strategies that magnify the costs resulting from systematic errors in California ISO forecasts.

- Scheduling and settling ancillary services and energy on the same basis will reduce inconsistencies resulting from the present system in which ancillary services are scheduled and settled based on RTPD prices, while real-time energy deviations are instead settled solely based on RTD prices.[6] Simultaneous scheduling and pricing of both ancillary services and energy will, for instance, cause ancillary service prices to reflect opportunity costs arising from actual energy schedules and prices. As another example, this element of the design change will allow resource shortages that trigger scarcity pricing of ancillary services in RTPD to propagate over to 15-minute energy prices that will be used for energy settlements under the proposed design.[7]

- Imbalances for all resources, including intermittent supply, should be settled at prices reflecting market conditions for the relevant intervals

From the point of view of each of these principles, the creation of a system of 15 minute market so that real-time exchanges, internal energy, and ancillary services are all priced on the basis of the same market optimization is appropriate. Of course, details in market design matter, and in the next section, we comment on a number of these details.

3. The CAISO Proposal

The California ISO's draft final proposal of March 26, 2013 has three main elements that we discuss below. The first set of changes involved the scheduling of interchange with other BAAs.

[6]Note that under the proposal, the 15 minute interval whose schedules and pricing will be binding for ancillary services and energy will occur 37.5 minutes after execution of RTPD. This is fifteen minutes later than the present RTPD system's first interval, which is when ancillary services are presently scheduled and priced.

[7]These shortage prices will not be reflected in RTD energy prices, but RTD prices will continue to be impacted by the load balance constraint when resources are scarce.

The second set of changes pertaind to real-time settlements for internal generation, load and virtual transactions. The third set of changes concerns the PIRP program.

A. Scheduling and Pricing of Interchange on a 15 Minute Basis

Instead of exclusively scheduling net interchange with adjacent BAAs in the HASP based on hourly transactions, the California ISO proposes to use the capabilities of its existing RTPD program to schedule interchange with adjacent control areas on a 15 minute basis. Market participants would continue to have the option to offer hourly interchange schedules that would continue to be scheduled in the HASP. These hourly transactions would include both hourly self-schedules and hourly transactions with economic bids. In addition, the California ISO proposes that two additional types of transactions could be offered in the HASP: (1) a self-scheduled variable energy resource forecast, and (2) hourly transactions with economic offers that allow for a single intra-hour schedule change.

In addition, the California ISO would allow market participants to submit economic bids for transactions that would be dispatchable every 15 minutes, whose dispatch would be evaluated and scheduled in RTPD. These economic bids would be fixed over the hour, but the California ISO would evaluate them over 15 minute time increments and the schedules could be changed every 15 minutes.

The California ISO would also maintain the ability of resources to dynamically transfer power in or out of the balancing areas. Because the rules and processes applicable to dynamic transfers will not be materially impacted by these changes, they are not discussed below.

Potential Benefits. The ability to schedule interchange on a 15 minute basis will have four advantages for the California ISO and its market participants. First, being able to adjust interchange schedules on a 15 minute basis will better allow the California ISO to align interchange levels with known, intra-hour demand and supply changes such as pumps starting or stopping or large generators coming on-line or going off-line.

Second, because the RTPD run that will be used to determine 15 minute interchange schedules will initialize roughly 37.5 minutes before the beginning of the schedule and 52.5 minutes before the end of the schedule, RTPD will be able to better align the level of imports with actual load levels than is the case with the HASP. HASP initializes 75 minutes before the beginning of the period and 2 hours and 15 minutes before the end of the hourly block period and hence is more prone to material load forecast error.

Third, scheduling some interchange on a 15 minute basis will provide the California ISO more flexibility in using adjustments in net interchange to accommodate changes in variable resource output and other changes in supply that cannot be anticipated in the HASP scheduling process.

Fourth, RTPD will be better able to match the level of imports to the level of demand, avoiding the typical pattern during ramping hours of RTD prices that plunge at the top of the hour when imports schedules increase, then rise steadily through the hour. This has the effect that the hourly

import schedules are uneconomic at the beginning of the hour and additional import supply would be economic at the end of the hour.

Settlement of Hourly Transactions. Another important element of the California ISO design that has been a subject of contention among some stakeholders is that there will be no bid cost recovery (BCR) for hourly transactions that are scheduled on an economic basis in the HASP but that turn out to be uneconomic, i.e., that do not recover their as-bid costs with RTPD prices over the course of the hour. The proposed design will settle real-time interchange transactions based on RTPD prices, rather than based on HASP prices. Significantly, hourly interchange schedules will be scheduled in the HASP based on the prices projected in the HASP, but the prices used for settlements will be the prices determined in RTPD. This design introduces the potential for hourly import transactions that are scheduled in the HASP to be paid less than their offer price if RTPD prices are lower than HASP prices. Conversely, there is a potential for exports scheduled in the HASP to be charged more than their bid prices if RTPD prices are higher than HASP prices.

The potential for import transactions to be paid less than their offer price could have some impact on offer prices, causing import suppliers to offer hourly supply at a slightly higher price so as to increase the likelihood that they will recover their costs. Any such increase in offer prices would be offset, at least in part, by the cost savings from avoiding the uplift costs associated with BCR. If this is the case, the actual likelihood of import suppliers on average recovering less than their offer prices may be very low and in general have little impact on either import offer prices or the elasticity of import supply.

Furthermore, price risk for import suppliers may be mitigated for some transactions by the feature of the ISO's proposal that gives importers a single curtailment option in which they can curtail the rest of the hour's schedule after any 15 minute market outcomes are announced in that hour. Thus, if, for instance, the first 15 minutes shows RTPD prices that are much lower than HASP prices, an importer who is concerned that it won't recover its bid cost can decide to cancel its schedule for the other three 15 minute intervals in that hour. It is possible that this provision will lessen the price risk for hourly transactions.

On the other hand, this curtailment provision may be of only marginal value in practice. First, it would be limited to hourly transactions involving FERC jurisdictional and other BAAs that allow mid-hour schedule changes for economic reasons. Second, this provision does not ensure that the underlying energy transaction will be curtailable if the market participant selling power into the California ISO market is distinct from the entity operating the generating resource that supplies the power. It is not clear whether or when a workable method will be developed to allow intra-hour curtailment of power sold under forward bilateral contracts and delivered into the California ISO. Third, this feature will not reduce price risk if the CAISO forward (advisory) RTPD prices (for second and subsequent intervals) are high relative to the financially binding RTPD prices, so that transactions that are uneconomic are not curtailed.

The relationship between HASP and RTPD prices, both in general and during particular conditions, such as high loads, will undoubtedly be analyzed by market participants as the implementation date for these changes approaches. The California ISO should similarly be

monitoring this relationship prior to implementation so as to anticipate and address any potential problems arising if the variability of RTPD prices relative to HASP prices introduces a material potential for losses by import suppliers offering supply during particular market conditions. Even if HASP prices are centered on RTPD prices on average, hourly suppliers may be somewhat risk averse and offer less supply if there is a perceived risk of large losses or opportunity costs under particular conditions. Any such potential reduction in the elasticity of import supply from hourly transactions will have little impact if it is offset by supply available at similar cost from 15 minute transactions. Whether this will initially be the case is uncertain, and it is also uncertain how rapidly the supply of 15 minute import supply transactions will increase over time.

While the potential for import suppliers selling power through hourly transactions to incur opportunity costs exists with the proposed design and may have some impact on the level and elasticity of offers of hourly import transactions, we agree with the California ISO's decision to not provide bid cost recovery for hourly transactions that turn out to be uneconomic at RTPD prices. The goal of the California ISO design is to move to a market design in which import suppliers and export buyers submit flexible 15 minute schedules. This goal risks being defeated if BCR is paid on hourly transactions to imports suppliers, so that the expected payment for hourly import transactions is higher than for 15 minute schedules even if the average hourly and 15 minute prices are the same. Moreover, if the California ISO were to provide bid cost recovery for hourly transactions on interfaces that allow 15 minute schedules, there would be a potential for market participants to submit offsetting hourly and 15 minute schedules that would generate net revenues when RTPD prices differ from HASP prices.[8]

Finally, the California ISO's design in which there is no BCR for price based hourly transactions is consistent with the approach the New York ISO took in implementing 15 minute scheduling. The New York ISO has historically settled price-based interchange transactions at real-time prices and paid BCR for economically scheduled transactions that do not recover their offer price at real-time prices. But as the New York ISO has introduced price-based 15 minute scheduling on its external interfaces over the past two years, it has eliminated its bid production cost guarantee for hourly transactions on those interfaces.[9] Moreover, other ISOs, such as the

[8] This would be similar to the problems that arose when California provided an intertie offer guarantee for both imports and exports under its Real-time Market Application software that was implemented on October 1, 2004. In part because of scheduling and pricing practices unique to the California ISO, this pricing system gave rise to extremely high uplift costs because market participants were able to submit offsetting import and export schedules, one or the other of which would qualify for an import offer guarantee, enabling the supplier to realize profits even when no power flowed, see See Department of Market Monitoring, California ISO, "2005 Annual Report, Market Issues and Performance," April 2006 pp. 1-2 to 1-4 and 3-24 to 3-25. Because of these problems, the California ISO's Real-Time Market Application pricing system was quickly modified by Amendment 66 effective March 25, 2005 to settle transactions on a pay-as-bid basis, See California ISO filing letter in Docket ER05-718-000 March 23, 2005; the change in the tariff was accepted by FERC in 111 FERC ¶61,008 April 7, 2005 effective March 25, 2005; See also Department of Market Monitoring, California ISO, "2005 Annual Report, Market Issues and Performance," April 2006 pp. 1-2 to 1-4 and 3-24 to 3-25.

[9] See New York ISO Filing in Docket ER11-2547-000, December 28, 2010.

Midwest ISO, do not even schedule interchange transactions based on bids and hence all interchange transactions are pricing taking, with no bid cost recovery.

Self-Scheduling Variable Energy Resources. While RTPD would determine binding interchange schedules for the 15 minute time period beginning roughly 37.5 minutes after it initializes and 22.5 minutes after it posts its results, HASP would determine advisory schedules for 15 minute offers over the four 15 minute intervals of each hour. An important element of the California ISO design is that while these advisory schedules for 15 minute intervals over the remainder of the hour will not be financially binding on the California ISO, in the sense that the California ISO will only schedule and pay for this interchange if the 15 minute interchange bid or offer clears in the RTPD run that determines the actual interchange schedules, the advisory schedules will require the market participant to adhere to these schedules if they are confirmed in RTPD. Hence, while a market participant submitting an economic bid for 15 minute schedules of import supply for the hour can subsequently reduce the amount of supply offered for the hour (by reducing its energy profile on the associated e-tag), it can only reduce its offers down to the level of the advisory schedules determined in HASP.[10] This rule is an important and necessary element of the overall design because it serves to ensure that if the HASP does not schedule an hourly interchange transaction based on the availability of a 15 minute transaction that could be dispatched during the hour, that 15 minute transaction will be available for dispatch during the hour. Since it is not assured that there will be a highly liquid supply of 15 minute transactions, the withdrawal of 15 minute schedules that received an advisory schedule in HASP could lead to substantial price volatility in RTPD and in RTD. Hence we support this element of the California ISO's proposed design.

There is, however, one feature of the California ISO's proposed design that allows this kind of inconsistency between HASP schedules and RTPD supply to arise. This is the treatment of self-scheduled variable energy forecasts. In determining advisory schedules, the HASP will treat these variable energy schedule as a normal transaction in its evaluation and hence will not schedule any advisory 15 minute transactions to account for the possibility that the output of the intermittent resource will not be not available in real-time. Furthermore, HASP will not consider the availability of such back-up 15 minute schedules to replace self-scheduled variable energy forecasts in choosing whether or not to schedule price-based hourly block transactions.

Hence, if the variable energy resource schedule is lower in RTPD than in the HASP, there is no assurance that 15 minute interchange transactions will be available to replace the variable energy schedule, nor is there a guarantee at what price level 15 minute replacement transactions might be offered. Conversely, variable energy schedules could also increase in RTPD relative to the forecast in HASP, creating additional price volatility if there is not a liquid supply of 15 minute interchange schedules that can be dispatched down in RPTD.

While the scheduling of imports from these variable energy resources in the HASP will generally be based on a California ISO forecast, this forecast will be made at least 75 minutes prior to the beginning of the hour and at least 2 hours before the beginning of the last 15 minute interval of the hour. Hence, there is a potential for differences between the level of variable energy resource

[10] California ISO, Draft Final Proposal, March 26, 2013, Section 5.2.3, p.15.

output projected at the time HASP initializes and the level projected during the operating hour. If there is a liquid market of 15 minute interchange transactions, the California ISO should be able to manage the variability of these intermittent resource schedules; however, there is no assurance that there will be a liquid market of 15 market schedules.

The California ISO already has to manage the uncertain real-time output of variable energy resources internal to the California ISO BAA, but the intra-hour variability of intermittent resource interchange schedules in the 764 design introduced by the proposed design will be in addition to the current level of intra-hour variability associated with internal intermittent resources. While the variability of the external intermittent resource transaction schedules will likely not be materially correlated with the short-term variability of internal resources, there would be some incremental impact on the overall variability of intermittent resource output delivered to the California ISO. Hence there is a potential for increased intra-hour variability in net load from this feature of the design that does not exist today. This is to a degree simply a consequence of Order 764, which tends to shift the impact of the uncertainty associated with intermittent resource schedules from the source BAA to the sink BAA. It is intended that the California ISO will be able to manage the variable output of these resources by dispatching up or down 15 minute interchange transactions during the hour. There is no assurance, however, that the amount of dispatchable 15 minute interchange schedules available will be sufficient to compensate for additional intra-hour changes in variable energy resource interchange supply.

Whether the intra-hour variability of intermittent resources schedules will pose any operational issues or creates any price risk will depend on the magnitude of the differences between the HASP and RTPD forecasts relative to the supply of 15 minute interchange transaction offers. Since 15 minute granular HASP forecasts have average errors on the order of 8%, there is a potential for significant differences in HASP and RTPD forecasts, especially as VER import schedules grow in future years.

B. Settlement of Internal Generation, Load and Virtual Transactions at RTPD prices

A second important element of the California ISO 764 design changes is that not only interchange transactions but all deviations between day-ahead schedules and RTPD schedules will be settled at RTPD prices. By settling internal and external transactions as well as virtual transactions at common RTPD prices, the proposed design will avoid the situation in which interchange transactions settle deviations from day-ahead schedules at different prices than virtual transactions.

RTPD and RTD Prices. The proposed design eliminates the potential for market participants to submit schedules intended to take advantage of predictable differences between HASP and RTD prices, which had contributed to very high real-time uplifts prior to suspension of convergence bidding on the interties. However, it needs to be recognized there is still a potential for differences between RTPD and RTD prices to give rise to additional costs. When RTPD prices and schedules are between the day-ahead prices and schedule and the real-time prices and schedule, the additional settlement will tend to reduce the volatility of real-time settlements and will not give rise to additional costs relative to purchasing power at the real-time price. Conversely, however, if the RTPD price and schedule are higher than both the day-ahead and

RTD prices or lower than both the day-ahead and RTD prices, these variations will tend to create additional costs that will be reflected in the average settlement price for power consumers. If the RTPD price is above both the day-ahead market price and the real-time price, additional supply will be bought in RTPD at the higher price, then sold back in RTD at a lower price. Conversely, if the RTPD price is lower than both the day-ahead price and the real-time price, supply purchased day-ahead will sold at a lower price in RTPD, then bought back at a higher price in RTD.

If the RTPD price is reasonably centered on the RTD price there will not be any undue costs associated with the proposed changes in the settlement system. However, if the RTPD price is systematically lower than the RTD price, so that the California ISO will systematically sell power at the RTPD price then buy it back at a higher real-time price, then the impact of these changes on the total cost of serving load may be material. In this regard, it is important to recognize that while the RTPD price should be more accurate relative to the RTD price than the HASP price, the amount of market volume being settled at the RTPD price, and hence the impact of systematic biases in the RTPD price will be larger than the impact of a similar systematic bias in the HASP price. All external and internal deviations from day-ahead market schedules will be settled at the RTPD price, whereas in the current design only deviations of interchange transactions from day-ahead schedules are settled at HASP prices.

Systematic biases in RTPD prices and schedules could also have a feedback impact on the day-ahead market. If RTPD prices and schedules were systematically low relative to RTD, for example, with the result that load serving entities were consistently selling back incremental day-ahead market schedules at lower RTPD prices, this pattern would make it profitable for load serving entities to reduce their day-ahead market schedules below their estimated real-time load to mimic the likely level of RTPD schedules. This would be cost reducing for a load serving entity because it would reduce the amount of market purchases that load serving entities would make day-ahead that would then be sold for a loss in RTPD.

In assessing the magnitude of this potential effect, it is important to recognize that uplift costs do not simply arise from RTPD prices that are lower than day-ahead market and RTD prices but from schedules that are lower. If RTPD schedules are very close to the day-ahead and RTD schedules, then little output will be sold at the RTPD price and little output bought at the RTD price, even if there is a real-time price spike due to real-time ramp constraints. The generators able to respond to the real-time dispatch instructions will, however, be paid the high price for their incremental output, providing an incentive for them to offer more ramp capability.

Data that was provided by the California ISO to market participants on day-ahead schedules, RTPD schedules and prices, and RTD prices and schedules indicate that the RTPD prices and schedules are reasonably well centered on RTD prices. Our calculations using these data suggest that this design would raise the real-time cost of power by only around $15 million a year relative to settling all deviations at RTD prices. However, the California ISO recently explained that the RTPD prices in that data are the T-22.5 prices rather than corresponding to the T-37.5 prices that would be used for settlements under the proposed design because the latter prices are

not currently being archived.[11] Moreover, the data provided is based upon aggregate weighted average data, rather than LAP data and prices, so the settlement impact would likely be larger than indicated by this calculation. It is important that the California ISO promptly begin archiving these 2nd interval data so that the relationship between RTD prices and the RTPD prices that will be used for settlements is understood by the California ISO and its stakeholders well before the proposed new settlement design is implemented.

The implication of these observations is that it will be important for the California ISO to focus on eliminating systematic differences between RTPD prices and schedules and RTD prices and schedules as it moves toward implementation of the new design.

Virtual Bidding at the Interties. A related change incorporated in the California ISO proposal is the reintroduction of virtual bidding at the interties. In the most recent version of the proposal, implementation of virtual bidding on the interties would be deferred until a year following the introduction of 15 minute interchange scheduling and settlements.

Under this design, virtual bids at the interties, internal virtual bids, interchange transactions, and deviations between day-ahead and RTPD schedules for internal load and generation will all settle at the RTPD price. With this change in pricing, virtual bids at the interties will settle at the same price as internal virtual bids, hence the pricing rule will not provide a mechanism for arbitraging systematic differences between RTD and RTPD prices.

In most ISOs and RTOs there is no compelling need to explicitly define virtual transactions on the interties, because unlike internal transactions in which only physical loads could otherwise buy power day-ahead and only physical generators could sell power day-ahead, any credit worthy market participant can schedule a physical import or export in the day-ahead market. Moreover, market participants in other ISOs and RTOs are free to, and often do, zero out interchange transactions between day-ahead and real-time if market conditions change. Hence, no other ISO or RTO has designs that include explicit virtual transactions on the interties.

There are, however, a few situations in which such an explicit identification of virtual interchange transactions might make sense, in part due to other unique California ISO policies and market rules. First, the explicit identification of particular interchange transactions as virtual transactions permits the California ISO to correctly account for these transactions in the RUC commitment and also to apply appropriate collateral policies to a virtual supplier on the interties.

A second situation in which the identification of an interchange transaction as virtual might make economic sense is unique to California and is a result of other California ISO market rules. California ISO rules will preclude a profitable settlement for day-ahead transactions that are

[11]See D. Tretheway, "FERC Order 764 Compliance Implementation of 15 minute scheduling and settlement," California ISO, Presentation, May 1, 2013, www.caiso.com/Documents/Presentation-FERC_Order764MarketChanges-DraftFinalProposalAddendumMay1_2013.pdf. The present RTPD system executes at T-22.5 minutes, where T is the start of the first 15 minute scheduling interval. Under the proposed Order 764 revisions, RTPD will be shifted, executing instead at T-37.5. As a result, the historical RTPD prices that are most relevant for the comparison we are making are the second interval prices (for the interval starting T+15, which is 37.5 minutes after execution).

uneconomic in real-time because real-time prices are lower than day-ahead prices, unless an e-tag is maintained through the HASP.[12] The existence of this rule may make it profitable for market participants to submit physical transactions as virtual transactions in the day-ahead market so that they can efficiently respond to real-time conditions without tagging transactions and perhaps without acquiring transmission for transactions that would not flow in real-time if they are no longer economic. Hence, because of these other market rules that are unique to the California ISO, there may also be a unique need for market participants to be able to schedule physical transactions as if they are virtual if the market participant intends to respond in an efficient manner to real-time market conditions.

Two other motivations for submitting virtual transactions might be that some other market participants are for some reason not submitting offers in the day-ahead market for transactions that consistently flow in real-time. This might in some circumstances create price discrepancies between the day-ahead market and real-time that might be arbitraged by virtual transactions at the ties if the transactions would contribute to congestion in real-time. However, if transactions were likely to create congestion in real-time, the physical supplier would be likely to schedule the transaction day-ahead if it were likely to flow.

Another perhaps more likely motivation is that virtual transactions might be used by market participants to profit from the congestion impact of real-time parallel (or "loop") flows not accurately modeled in the day-ahead market. If the California ISO were to predictably fail to accurately account for parallel flows or other factors leading to real-time transmission deratings in the day-ahead market, this would lead to predictable price discrepancies between day-ahead and real-time that might be arbitraged by virtual trades.

The reintroduction of virtual trading on the ties leads to two sets of related changes in the California ISO market design. These are the reintroduction of position limits for virtual transactions on the ties and the application of rules to address the situation in which virtual transactions provide counterflow on constrained interfaces in the day-ahead market.

The introduction of position limits is apparently motivated by the goal of reducing the potential for large uplift costs arising from virtual bids at the interties.[13] The position limits, however, only limit the positions of individual market participants, not the total collective positions of all market participants. The position limits may therefore effectively constrain the ability of individual market participants to take substantial advantage of market design flaws that they might be uniquely situated to take advantage of. However, if flaws in the market design, settlement design, or transmission system modeling are apparent to--and can be taken advantage of by--a broad base of market participants, then those limits would be less effective in preventing material uplift costs.

The change in the pricing rules proposed by the California ISO will avoid the uplift costs that occurred over the past two years due to differences in settlement prices for intertie transactions and virtual bids. However, uplift due to virtual bids designed to profit from parallel flows or

[12] California ISO, Draft Final Proposal section 5.1 p. 26.

[13] California ISO, Draft Final Proposal section 8.3 pp. 28-29.

other deratings that are not modeled in the day-ahead market could exist and these uplift costs will not be very effectively limited by position limits if these modeling issues are recognized by a broad set of market participants.[14] Consequently, the risk of large such uplifts will need to addressed by avoiding such predictable differences between day-ahead and real-time limits.

The other change related to the introduction of virtual bidding at the interties are the rules the California ISO has introduced to address the potential for virtual transactions on the interties to provide counterflow in the day-ahead market that allows physical transactions in excess of the scheduling limit to clear in the day-ahead market. The California ISO proposes to allow these physical transactions in clear in the day-ahead market but will limit the number of transaction e-tags it accepts day-ahead for physical transactions to those that are feasible absent the counterflow provided by the virtual transactions. The proposed rules introduce the possibility that some physical import transactions that clear in the day-ahead market might not be able to submit e-tags day-ahead. However, the physical transactions able to submit e-tags will exhaust the transfer capability of the grid and if some transactions that submit e-tags day-ahead do not clear in RTPD, transactions that did not get tags day-ahead will be able to flow in real-time.

It is likely that virtual traders will not submit substantial amounts of counterflow transactions on constrained interfaces, as such transactions have a potential to incur large losses if market participants with day-ahead schedules submit low bids in RTPD to ensure that their import transactions flow (or high bids to ensure that their export transactions flow). By pricing physical and virtual transactions consistent with their schedules, the California ISO will eliminate the incentives that could motivate the scheduling of counter flow virtual transactions and gave rise to pricing inconsistencies within the HASP settlement design. Hence, while the California ISO's approach to taking account of counterflow virtual transactions is somewhat ad hoc, it is reasonable to anticipate that the pricing system will deter virtual traders from submitting such counterflow transactions, so the California ISO design is likely to be workable.

C. Participating Intermittent Resource Program

The third set of changes pertain to the Participating Intermittent Resource Program (PIRP) program, which would be retained, but modified in several ways made possible by the associated market changes. First, the schedules used for settlements of PIRP and other intermittent resource schedules would be determined in RTPD rather than in the HASP. Hence they would be determined much closer to real-time, 37.5 minutes prior to the beginning of the schedule rather than 90 minutes to 2-1/4 hours before the beginning of the 15 minute period under the current design. This change will allow more accurate intermittent resource schedules to be submitted. Another important change is that PIRP resources will be able to submit economic bids that will allow intermittent resources participating in the PIRP program to be dispatched down when price are too low for the intermittent resource generation to be profitable. Third, these changes will allow and require intermittent resources participating in PIRP to settle deviations between their

[14] Position limits would potentially reduce the potential profits to an individual market participant from identifying such inconsistencies.

RTPD schedule and real-time output dispatch to be settled at real-time prices during each interval, rather than netted over the month.[15]

This design will align prices, schedules and incentives because the RTPD price used to settle variable energy resource schedules will reflect the value of the power in the RTPD time frame in which the California ISO can accommodate changes in intermittent resource output both by adjusting net interchange and by adjusting the output of internal resources. Meanwhile deviations between the RTPD forecast and a resource's real-time output will be settled at real-time prices, which will reflect the cost of resources available to accommodate changes in output in the time frame of the real-time dispatch.

Another desirable feature of this element of the California ISO proposal is that by maintaining the PIRP program, it avoids unnecessary triggering of renegotiation of existing contracts that directly or indirectly require or assume that the intermittent resource participate in the PIRP program.

We note that there is not a consensus among stakeholders that this proposal adequately satisfies all concerns with the transition from the previous PIRP design. If any grandfathering exceptions are made for existing contracts, we strongly recommend that any such exceptions not affect market efficiency and be strictly limited in time and scope.

4. Recommendations

We support the three key elements of the California ISO proposal. The introduction of 15 minute scheduling is not only necessary to comply with FERC Order 764, it offers the potential to improve the performance of California ISO markets (and indeed markets throughout the West) and reduce the cost of meeting load by enabling more optimal scheduling of interchange with adjacent BAAs. The associated changes in the settlement of interchange transactions and virtual bids (in which they are based on binding RTPD prices) should allow net interchange to be settled at prices that are better aligned with real-time prices than is the case with the present HASP-based settlement process for interchange. Finally, we anticipate that scheduling interchanges involving intermittent resources closer to real-time and allowing internal and external intermittent resources to be dispatched based on price will have several benefits. In particular, this element of the proposal should improve the California ISO's ability to balance load and generation in real-time with reduced price volatility; enable external variable energy resources to supply power to California at lower cost; and allow internal variable energy resources to participate more efficiently in the real-time market.

There are some risks associated with the implementation of these changes which will need to be analyzed by the California ISO as this design moves toward implementation as well as monitored following implementation.

[15] California ISO, Draft Final Proposal, Section 7, pp. 22-23.

- First, there will not necessarily be a liquid supply of 15 minute interchange bids and offers when the California ISO design is first implemented. If this is the case, then uncertainty concerning the impact of implementing these changes could lead to somewhat higher offer prices for import supply. Further, it should be anticipated that the overall elasticity of import supply in real-time, both hourly and 15 minute transactions, may, at least initially, be somewhat lower than under the current design. There will, however, be offsetting benefits in the form of reduced costs from uneconomic import and export transactions. The California ISO will need to monitor the relationship between prices projected in HASP and binding RTPD prices and make changes needed to maintain convergence to help maintain the elasticity of import supply.

- Second, while settling interchange transactions at RTPD prices determined closer to real-time should tend to reduce uplift costs (real-time energy offset costs) relative to the current design, settling internal generation and load deviations from day-ahead schedules at RTPD prices and then settling deviations from RTPD schedules at RTD prices will give rise to new uplift costs. We anticipate that the net effect of these changes will likely be a reduction in overall uplift costs relative to the current design. Nonetheless, the California ISO will need to carefully monitor the relationship between RTPD solutions and the real-time dispatch to minimize both systematic errors and large random errors in order to achieve the intended benefits of these design changes. We also recommend that the California ISO promptly begin archiving second interval RTPD data so that the relationship between RTD prices and the RTPD prices that will be used for settlements is understood by the California ISO and its stakeholders well before the proposed new settlement design is implemented.

- Third, if the supply of 15 minute interchange bids and offers is initially not very liquid, the elements of the design that allow output-contingent intermittent offers to displace fixed hourly import schedules may contribute to the volatility of RTPD and RTD prices. This potential can be studied prior to implementation and managed by the way the California ISO forecasts variable resource output for the hour-ahead scheduling process.

Attachment J – Declaration of Donald Tretheway

Real-Time Market Design Enhancements Related to Order No. 764

California Independent System Operator Corporation

November 26, 2013

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)**	**Docket No. ER14-____-000**

DECLARATION OF
DONALD TRETHEWAY
ON BEHALF OF THE
CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

Q. Please state your name, title, and business address.

A. My name is Donald Tretheway. I am employed as Lead Market Design and Regulatory Policy Specialist for the California Independent System Operator Corporation ("ISO"). My business address is 250 Outcropping Way, Folsom, CA 95630.

Q. Please describe your educational and professional background.

A. I have a Bachelor of Arts in Economics, with a specialization in Computing, from the University of California, Los Angeles and a Masters of Business Administration, Finance & Technology Management, from the University of California, Davis - Graduate School of Management.

I began working at the ISO in June 2009 and have worked on a number of significant market design issues. I was policy lead on the ISO's initiative to comply with the requirements established by the Federal Energy

Regulatory Commission ("FERC") in Order No. 755 concerning procurement of frequency regulation in the organized wholesale electric markets. I also played a significant role in the ISO's Renewable Integration Market & Product Review initiative and the ISO's prior stakeholder initiatives addressing intertie pricing issues.

Q. What are your duties and responsibilities at the ISO?

A. I am responsible for the development of enhancements to the wholesale electricity markets administered by the ISO with an objective of improving the efficiency of those markets and facilitating the realization of regulatory and public policy objectives in the region.

Since the summer of 2012, immediately after Order No. 764 was issued, I have been policy lead on the stakeholder process used by the ISO to develop its proposal to implement 15-minute scheduling and settlement and related market design enhancements that will satisfy the intra-hour scheduling requirements established by the FERC in Order No. 764 and that will allow the ISO's real-time market to more efficiently integrate a large amount of renewable variable energy resources into the fleet of resources serving customers in the ISO's balancing authority area.

Q. What is the purpose of your declaration?

A. First, I will provide an overview of the market design changes the ISO has developed to address the Order No. 764 directive to provide an option for market participants to schedule energy in 15-minute increments and the related market design changes which go beyond the minimum requirements of Order No. 764 to provide other benefits to customers. This overview will include examples that illustrate the mechanics of the new market design.

Second, I will explain why the ISO chose to structure the pricing and settlement features of the enhanced market design as it has. Among other things, I will explain why the ISO is proposing a distinct 15-minute settlement under the new market design, as opposed to settling on an average of the three five-minute intervals, and why the ISO determined that deviations between the new fifteen-minute market ("FMM") and real-time prices should not be settled at the "worse of" price.

Lastly, I will describe features of the enhanced market design specific to variable energy resources, including related changes to the ISO's participating intermittent resource program and proposed protective measures for older intermittent resources that may have technological or contractual restrictions preventing them from responding fully to ISO dispatch instructions.

Elements of the ISO proposal related to the reinstatement of convergence bidding on the interties between the ISO balancing authority area and neighboring balancing authority areas will be addressed by my colleague Gregory Cook, Director of Market Design and Regulatory Policy for the ISO.

Q. Will you be using any specialized terms in your declaration?

A. Yes. Unless otherwise indicated, specialized terms in my declaration have the meanings set forth in the Master Definitions Supplement, Appendix A of the ISO tariff.

I. Background

Q. Please briefly describe the FERC directives addressed in the ISO's market design changes.

A. Order No. 764 directed transmission providers like the ISO to remove barriers to the integration of variable energy resources by requiring each transmission provider to: (1) offer an option to schedule energy with 15-minute granularity; and (2) require variable energy resources to provide meteorological and forced outage data for the purpose of power production forecasting. For the ISO, the primary changes to address the 15-minute scheduling option required by Order No. 764 are to intertie

transactions since internal resources already are dispatched every five minutes in the ISO's markets.

Order No. 764 only requires that transmission providers in organized wholesale electricity markets offer resources an option to update energy schedules on interties every fifteen minutes. It does not require a transmission provider to require 15-minute energy scheduling for interties, nor does it address internal resource scheduling. However, Order No. 764 does allow a transmission provider to propose an approach that is consistent with or superior to the specific intra-hour scheduling reforms mandated by the Order.

Q. Why did the ISO decide to develop market enhancements beyond the minimum changes needed to comply with the 15-minute scheduling requirements of Order No. 764?

A. The ISO concluded that the directives in Order No. 764 created an opportunity to implement real-time market design changes that will facilitate improved integration of renewable variable energy resources as well as address identified inefficiencies in the ISO's current hour-ahead/real-time market design. After I describe the ISO's proposed real-time market design changes, I will explain why the ISO has concluded that these changes are superior to the minimum changes needed to comply with the 15-minute scheduling requirements of Order No. 764.

Q. Please provide a summary of the ISO's current hour-ahead scheduling process/real-time market structure.

A. The current real-time market is composed of three distinct market optimizations:

- The real-time unit commitment ("RTUC") establishes financially binding ancillary services awards and unit commitment for internal generation. The real-time unit commitment is a market optimization run that performs a security constrained unit commitment with 15-minute granularity based on a forecast for ISO demand. The real-time unit commitment optimization function performs a security constrained economic dispatch that establishes financially non-binding energy schedules for the interval in which it is run and subsequent intervals within its time horizon.

- The current hour-ahead scheduling process ("HASP") establishes hourly financially binding energy and ancillary services for non-dynamic (*i.e.*, static for the hour) intertie transactions based on optimization of the forecast of internal demand and bid-in exports. The hour-ahead scheduling process is a special run of the real-time unit commitment described above that performs the additional task of clearing the interties.

- The real-time dispatch ("RTD") then establishes financially binding energy dispatches for internal generation and dynamically scheduled intertie transactions every five minutes through a security constrained economic dispatch. The real-time dispatch uses the same tools as the real-time unit commitment to forecast demand but applies those tools at different times than does the real-time unit commitment. The real-time dispatch market optimization is based on a forecast of demand (including losses) and data from the ISO's state estimator. Load is settled pursuant to the real-time dispatch based upon the actual metered demand.

Q. Has the ISO identified any inefficiencies with this real-time market structure?

A. Yes. The real-time imbalance energy offset is a real-time neutrality account used to reconcile settlement dollar values for all real-time energy charge codes to ensure that, after all payments and charges have been

calculated, there is neither a shortage nor a surplus in revenue. The ISO had experienced real-time imbalance energy offset charges that were higher than expected since the implementation of its current market design in April 2009. Through the ISO's own analysis and stakeholder input, the ISO and stakeholders determined a root cause of the market inefficiencies under the current market design is the fact that intertie transactions are financially binding based on hour-ahead scheduling process locational marginal prices ("LMPs"), however, load and internal generation are financially binding based on real-time dispatch LMPs. The hour-ahead scheduling process and real-time dispatch optimizations run at different times and with different market interval durations. As a result, system conditions are not aligned when running these applications which results in price divergence between hour-ahead scheduling process prices and real-time dispatch prices and market uplifts in the form of real-time imbalance energy offset charges.

Q. Were there prior stakeholder processes to address these real-time market inefficiencies?

A. Yes, the ISO conducted several stakeholder process to address aspects of these market inefficiencies. First, in 2009, the ISO initiated a stakeholder process called Real-Time Imbalance Energy Offset that culminated in FERC acceptance of tariff revisions to exempt load and

exports of load following metered subsystems (“MSS”) from the allocation of real-time imbalance energy neutrality offset charges.

In April 2011 the ISO initiated a new stakeholder effort called Real-Time Imbalance Energy Offset (2011), to evaluate and consider measures to address continued increases in real-time imbalance energy offset. The ISO determined that the real-time imbalance energy offset increases were caused by charges and payments due to differences between the hour-ahead scheduling process prices for convergence bidding transactions at the interties and the real-time dispatch prices for internal convergence bidding transactions. The ISO also began a second stakeholder initiative in April 2011 called Price Inconsistency Caused by Intertie Constraints, in order to address instances where physical imports and exports might clear inconsistent with their bid prices in the day-ahead market due to the enforcement of dual constraints to accommodate virtual bidding at the interties.

The ISO combined those two stakeholder initiatives and, pursuant to the initiatives, filed for and obtained FERC acceptance of a tariff amendment to discontinue convergence bidding at the interties effective November 28, 2011. In late 2011, the ISO established a new stakeholder initiative, called Intertie Pricing and Settlement, to determine long-term solutions to address the real-time imbalance energy offset and pricing inefficiencies between the hour-ahead scheduling process and the real-time market

identified during the two initiatives established in April 2011. During this stakeholder effort, the ISO considered certain alternatives to address the intertie pricing issues, but did not reach any viable conclusions.

Q. In the course of these and other stakeholder processes, did the ISO and stakeholders consider the possibility of redesigning the real-time market?

A. Yes. In the spring of 2011, the ISO initiated a stakeholder process called the Renewable Integration: Market and Product Review Phase 2 initiative to examine a range of potential measures to enhance the ISO's wholesale energy markets in order to facilitate the integration of the increased level of renewable resources in the ISO's resource fleet expected as a result of California's renewable portfolio standards and environmental policies.

The ISO discussed with stakeholders a potential redesign of the real-time market to a 15-minute dispatch and a new balancing product to manage changes between the dispatch and regulation. But it was concluded that it would be unlikely for neighboring balancing authorities in the Western Electricity Coordinating Council ("WECC") region to accommodate 15-minute scheduling in the next two to three years. Also, the implementation complexity of the 15-minute dispatch design would not be achievable in two to three years due to significant software changes required for implementing a new balancing product which was considered at one point

as an alternative to the current real-time dispatch market optimization. As described below, the ISO's market design enhancements retain the five-minute real-time dispatch market optimization.

Q. How did the issuance of Order No. 764 change the context in which the ISO considered these issues?

A. Order No. 764 mandated that all transmission providers make available the opportunity for 15-minute schedules. This essentially shortened by a significant amount the estimated timing for the implementation of 15-minute scheduling in other parts of the WECC region. The prospect of having more granular scheduling in the Western United States sooner made it more worthwhile for the ISO to take on any real-time market reforms. As such, Order No. 764 created an opportunity for the ISO to implement real-time market design changes related to intertie transactions that were not possible before the FERC mandated the reforms in the order. Following the issuance of Order No. 764, the ISO initiated a new stakeholder process, called FERC Order No. 764 Market Changes, that allowed the ISO and stakeholders to develop real-time market design changes that are expected to address most of the real-time market inefficiencies described above. The issues that were being considered in the Intertie Pricing and Settlement stakeholder effort were subsumed and addressed in the Order No. 764 stakeholder process. In addition, as explained in the Declaration of Mr. Cook, these design changes are

expected to address real-time price divergence issues and allow for the reintroduction of convergence bidding on the interties after a period of experience with the enhanced market design.

II. Overview of the ISO's Market Design Changes

Q. Does the new market design build on the ISO's current real-time market structure?

A. Yes. The new real-time market design will retain many of the features of the current real-time market structure while also including a number of enhancements to the current structure. As described below, the new real-time market design will retain hourly scheduling options to facilitate transactions with the rest of the Western United States. While the new market design will not change these aspects of the current real-time market, it will leverage the existing real-time unit commitment market functionality to establish 15-minute financially binding schedules for energy and ancillary services for all internal transactions and for all transactions on the interties. This component of the revised market design is called the fifteen-minute market. Internal resources and dynamically scheduled resources will continue to be dispatched by the real-time dispatch on a five-minute basis, as they are today. The new hour-ahead scheduling process will serve a more limited function than does the hour-ahead scheduling process under the current market design. It will only be used to determine scheduled quantities for intertie

transactions of market participants that choose one of the hourly scheduling options I discuss below. The revised hour-ahead scheduling process will accept intertie hourly block schedules that will be price-takers over the four 15-minute intervals of each hour. Thus, pricing will be on a 15-minute basis for all real-time transactions under the new market design.

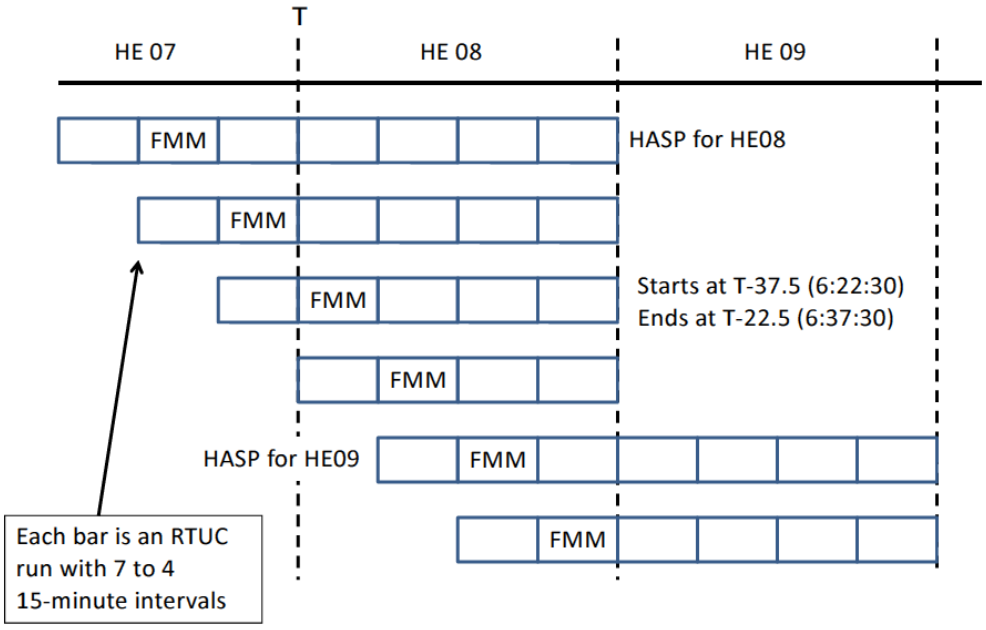
The overall bidding timeline will remain the same. Scheduling coordinators will continue to bid and participate in the real-time market process as they do today. That is, bids will still be submitted on the same timeline, 75 minutes before the hour. However, as described below, the ISO proposes changes that will allow variable energy resources the ability to submit updated forecasts closer to real-time schedules to avoid imbalance energy charges.

Q. Please explain how real-time unit comment is related to the new hour-ahead scheduling process and fifteen-minute market.

A. Figure 1 below depicts the intervals that will apply under the revised market design for the real-time unit commitment, hour-ahead scheduling process, and fifteen-minute market under the revised market design (with "HE" standing for "hour ending"). As shown in Figure 1, the first RTUC run for an hour will begin with seven 15-minute intervals, followed by an RTUC run with six 15-minute intervals, then an RTUC run with five 15-minute

intervals, and an RTUC run with four 15-minute intervals. The seven-interval run is the HASP run for the upcoming trade hour and the fifteen-minute market for the third 15-minute interval in the preceding hour.

Figure 1 – Application of HASP, RTUC, and FMM Under the Revised Market Design



All operational instructions go through the real-time dispatch. The real-time unit commitment commits units for four to seven intervals within its time horizon. Units committed in a given real-time unit commitment may or may not have a fifteen-minute market schedule for the same interval in which it is executed. The real-time unit commitment process commits units to their minimum operating level (PMin) in each run and its decisions, along with other dispatch instructions, are conveyed through the real-time

dispatch. The fifteen-minute market consists of the schedules determined in the second 15-minute interval of the real-time unit commitment. Under the new market design, as is the case today, the real-time unit commitment and the real-time dispatch work in concert to ensure units are committed and then dispatched to meet system needs.

Q. Please provide an overview of the hour-ahead market intervals under the new market design.

A. The ISO proposes to replace the current hour-ahead scheduling process with a new hour-ahead scheduling process that will provide options to submit block schedules on the interties. The fifteen-minute market run will dispatch other intertie transactions. Figure 2 below provides an overview of the hour-ahead market intervals under the new market design:

Figure 2 – Hourly Process for Real-Time Market

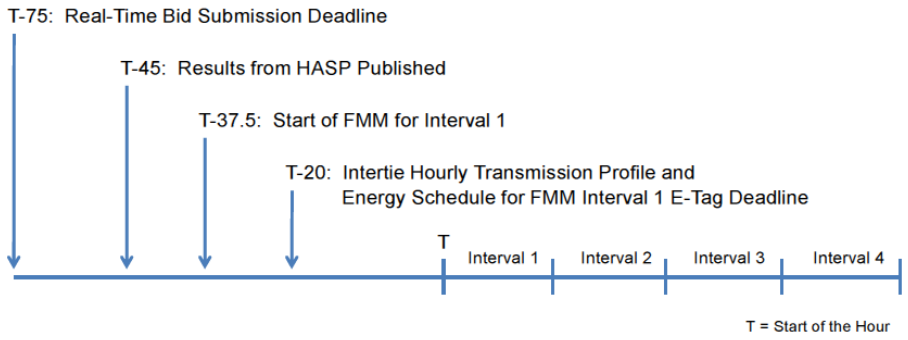


Figure 2 illustrates the timeline for the hour-ahead scheduling process optimization, fifteen-minute market optimization for the first 15-minute interval of the hour, and e-tagging deadlines for transmission profiles and energy schedules. Deadlines for the remaining fifteen-minute markets in each hour will be 15 minutes after the deadlines for Interval 1. For example, the Interval 2 optimization will start at T-22.5 while the deadline for submitting e-tags for intertie transactions for Interval 2 is at T-5, and so on.

Q. Why is it important to provide options for hourly block schedules under the new market design?

A. The ISO believes that many parties scheduling transactions over the ISO's interties with neighboring areas will take advantage of 15-minute energy scheduling. However, over the next few years, many transmission reservations and energy transactions within WECC are likely to remain

hourly. Retaining the options for hourly block schedules ensures that the new ISO real-time market design does not create seams issues with the rest of the Western Interconnection.

Q. What other scheduling considerations did the ISO take into account in developing the real-time market design enhancements?

A. In was necessary to take into consideration the existing deadline imposed by WECC that requires e-tags for intertie transactions to be submitted 20 minutes prior to the operating interval. There is no indication that WECC, the North American Electric Reliability Corporation ("NERC"), the North American Energy Standards Board ("NAESB") or FERC will modify existing e-tag deadlines in the near future. Under the ISO's new real-time market design, the ISO will no longer establish settlement prices through the hour-ahead scheduling process. Rather, under the revised market design the ISO will award hourly, binding energy schedules for intertie transactions. The ISO will then clear and settle these intertie energy schedules as price takers in the fifteen-minute market. In order to align with the 20-minute e-tag submission deadline, the ISO has aligned the intervals for the fifteen-minute market such that the market results are consistent with WECC e-tagging practices. To ensure that scheduling coordinators can have the benefit of this requirement, the ISO systems also will automatically update energy schedules on e-tags to facilitate participation in the fifteen-minute market on the intertie. If WECC moves

to 15-minute transmission reservations and shorter e-tag intervals in the future, the ISO can at that time investigate how to further enhance the real-time market design to run the fifteen-minute market closer to actual flow.

Q. Please describe bid submission in the new real-time market

A. The ISO will retain hourly submission of bids to the real-time market. These bids will be used to:

- Economically accept hourly block schedules at the interties;
- Economically schedule resources for energy and ancillary services from all resources, including interties and internal supply, in the fifteen-minute market; and
- Economically dispatch resources in the 5-minute real-time market runs.

The bid submission interval has the same deadline as applies under the current real-time market design. The same economic bids will be used in each market optimization (the new hour-ahead scheduling process, the fifteen-minute market, and the real-time dispatch). The ISO is not proposing any changes to the hourly bid information provided by internal generation. As is currently the case, load will clear based on ISO forecasted demand. Therefore, load serving entities will still not be allowed to bid their load in the real-time market. However, just like today, the ISO will continue to accept bids for exports at the interties.

Q. Please provide an overview of how variable energy resources bid in the new real-time market.

A. Variable energy resources that plan to use their forecast unless the price is below a certain amount can use an economic bid curve to indicate their willingness to forgo the forecast schedule. If the economic bid curve is submitted, the forecast schedule will essentially be used as a cap on the economic bid curve for both the fifteen-minute market and real-time dispatch allowing the fifteen-minute market and real-time dispatch to clear. This will provide the ISO with a mechanism to economically curtail variable energy resources below their forecasted output, which will provide significant reliability benefits in over-generation conditions and will provide further benefits in the future when the ISO implements the flexible ramping product. In addition, the ISO will continue to forecast the variable energy resource's output even if the resource has been curtailed previously, which provides a mechanism for dispatching the resource up when over-generation conditions are no longer present. This additional bidding functionality and flexibility for bidding by variable energy resources is described in more detail later in my declaration.

Q. How will bids submitted by resources seeking to use the interties change under the ISO's proposal?

A. The ISO will run separate processes for accepting hourly block schedules and determining binding energy schedules and ancillary services awards. Intertie resources will submit the following information:

- Energy self-schedules and/or energy bids (this is unchanged from the current market design);
- Ancillary services bids (this is unchanged from the current market design);
- An optional flag for the bid to be considered as an hourly block schedule; and
- An optional flag to allow a single schedule change for the remainder of the hour for accepted block schedules.

A. The New Hour-Ahead Scheduling Process

Q. What are the bidding/scheduling options for intertie transactions under the enhanced market design?

A. The following six bidding/scheduling options will be available for intertie transactions:

1. Self-scheduled hourly block;
2. Self-scheduled variable energy resource forecast;
3. Economic bid hourly block;
4. Economic bid hourly block with a single intra-hour schedule change;
5. Economic bid with participation in the fifteen-minute market (which may or may not be linked to a variable energy resource forecast); and
6. Dynamic transfer.

The availability of hourly block options ensures the new market structure does not create seams issues as the rest of the WECC transitions to 15-minute transmission and/or energy scheduling.

Q. Please describe the option of self-scheduling or economically bidding variable energy resources based on forecasted output under the new market design.

A. External variable energy resources submitting schedules over the interties can use the ISO forecast for their 15-minute expected energy in the new hour-ahead scheduling process to accept block schedules. The ISO will have procedures to qualify these resources to do so. If external variable energy resources opt to schedule using the ISO forecast, they will be charged the forecast fee that is currently applied to all Eligible Intermittent Resources and they will not be subject to the intertie schedules decline charge for their variable energy resource schedules. An external variable energy resource can also use its own forecast of expected energy and will not be subject to the forecast fee. However, if the expected energy is not delivered in the fifteen-minute market, a variable energy resource using its own forecast will be subject to the intertie schedules decline charge, as discussed in more detail below. This ensures that variable energy resources using their own forecasts do not overstate expected energy that "crowds out" schedules from resources other than variable energy

resources in the hour-ahead scheduling process. Since the advisory energy schedule that clears from the new hour-ahead scheduling process to accept block schedules is not financially binding is not financially binding for a variable energy resource that uses the 15-minute scheduling functionality on the interties, this penalty mechanism is used to incentivize forecasting actual expected energy. The intertie schedules decline charge will also apply to other intertie transactions that do not e-tag an accepted hourly block schedule which is advisory.

Q. Please describe the option of an economic bid hourly block with a single intra-hour schedule change under the new market design.

A. In order to increase the amount of energy schedules that can change in the 15-minute process, the ISO proposes to allow hourly block schedules the option of being economically dispatched once in the hour. Given the expanded role of variable resources in the western United States, the ISO believes entities throughout the WECC region will take advantage of 15-minute energy scheduling. However, over the next few years, transmission reservations within WECC are likely to remain predominantly hourly. Currently, WECC has established business processes that support a single intra-hour schedule change of intertie schedules. While the WECC provisions are for reliability, rather than economic curtailments, it is reasonable to expect that these processes could be adapted to

accommodate economic curtailments. In making economic dispatch determinations, the ISO's software performs a multi-interval optimization.

The proposed single intra-hour schedule change of intertie schedules will work as follows for a curtailment:

- Assume an hourly block import has a bid of $50. In the new hour-ahead scheduling process to accept block schedules, the import is accepted for 100 MW.
- In the fifteen-minute market, the LMP is $55 and the import is economic across the applicable RTUC horizon (in this example, the remainder of the operating hour). Therefore, the import flows and is paid $55.
- Then in the next RTUC run, the fifteen-minute market LMP drops to $45 and the import is not economic across the applicable RTUC horizon (in this example, the remainder of the hour). The import is curtailed and does not flow in intervals 2, 3, and 4.
- If in the fifteen-minute market for intervals 3 and 4, the price increased to $55, the import schedule would remain at the curtailed level in interval 2.
- In intervals 3 and 4, the import is paid the relevant LMP for 100 MW.

The proposed single intra-hour schedule change of intertie schedules will work as follows for an incremental increase in output:

- Assume an hourly block import has a bid of $50. In the hour-ahead scheduling process to accept block schedules, the import is accepted for 50 MW.
- The lowest transmission profile (*i.e.*, the transmission information included in an e-tag) that is e-tagged in a neighboring balancing authority at T-37.5 is equal to 100 MW. The ISO market optimization will not award energy schedules that exceed the lowest transmission profile e-tagged at the start of the binding fifteen-minute market optimization. However, any portion of a bid submitted in the new hour-ahead scheduling process that exceeds the lowest transmission profile will remain viable, and the ISO may accept

that portion of the bid in the fifteen-minute market to the extent that a transmission profile is provided for it in the fifteen-minute market.

- In the fifteen-minute market, the LMP is $55 but is only economic for the balance of the hour at 50 MW, and the energy schedule is unchanged and is paid $55.

- Then in the next RTUC run, the fifteen-minute market determines that the import is economic for the remainder of the hour at 100 MW. Therefore, the energy schedule is increased to 100 MW and will remain at that level for intervals 3 and 4.

- In intervals 3 and 4, the import is paid the relevant LMP for 100 MW.

Q. Please explain whether bid cost recovery will apply under the various intertie transaction options.

A. For the first two options for scheduling or bidding intertie transactions described above (the self-scheduled hourly block and self-scheduled variable energy resource forecast options), no bid cost recovery applies under the current market design nor will it apply under the new market design.

For the third and fourth options (the economic bid hourly block and economic bid hourly block with a single intra-hourly schedule options), a resource is eligible for bid cost recovery under the current market design but it rarely, if ever, receives bid cost recovery. For similar schedules in today's hour-ahead scheduling process, the resource is only cleared at the interties if it is economic, in which case the resource's revenues exceed its costs and thus the resource does not in fact ever receive bid cost

recovery. One objective of the new market design is to provide an incentive for import suppliers and export buyers to submit flexible 15-minute bids. This goal would be undermined if bid cost recovery were to be paid on hourly transactions to import suppliers, such that the expected payment for hourly import transactions would be higher than for 15-minute schedules – even if the average hourly and 15-minute prices were the same. Also, if bid cost recovery were allowed under these options, market participants might submit an hourly import schedule and a 15-minute export schedule that would generate net revenues because the import schedule would receive bid cost recovery and the export schedule would be settled at the lower 15-minute price.

However, it is appropriate to apply bid cost recovery for the fifth and sixth intertie transaction options (the economic bid with participation in the 15-minute market and dynamic transfer options). As a result of the new market design clearing the market optimization across the applicable horizon, it is possible that a resource exercising one of those options could be below its bid price in the financially binding interval because the resource made up for it in later intervals. If system conditions do not materialize as expected, then the LMP may not be the same as when the original decision was made to schedule the resource in the prior 15-minute interval. In those circumstances, bid cost recovery is appropriate.

Q. How will the new hour-ahead scheduling process accept block schedules?

A. Under the proposed fifteen-minute market design, there no longer will be financially binding hour-ahead prices for energy and ancillary services over the interties. Leveraging the existing real-time unit commitment market functionality, the ISO has modified the market structure so that it can determine financially binding energy and ancillary services schedules and prices within each 15-minute interval. The ISO will determine these simultaneously for each 15-minute interval based on energy self-schedules and energy and ancillary services bids.

The new hour-ahead scheduling process will accept hourly block schedules and provide advisory 15-minute energy schedules and ancillary services awards. The results will be published at 45 minutes prior to the applicable trade hour, which is the same time as hour-ahead scheduling process schedules are published under the current market design. These results will be used for e-tagging hourly transmission profiles.

Q. Please continue.

A. In the new hour-ahead scheduling process to accept block schedules, the market optimization will enforce a constraint to ensure that, for each 15-minute interval, the energy schedule of submitted hourly block schedules will be equal. In the financially binding fifteen-minute market, the accepted

hourly block schedule will be considered a self-schedule. For the self-scheduled variable energy resource forecast, the market optimization will use the forecasted energy for each 15-minute interval. In the financially binding 15-minute interval, the variable energy resource can update its self-schedule based on the most current forecast which will be used in the fifteen-minute market.

For economic bids submitted in the fifteen-minute market and for dynamic transfers, the hour-ahead scheduling process will produce advisory energy schedules for each 15-minute interval. The energy schedule in the financially binding fifteen-minute market can be different than the advisory schedule that cleared the hourly process to accept block schedules. However, the 15-minute energy schedule cannot exceed the transmission capacity as reflected in e-tags prior to the start of the binding fifteen-minute market optimization.

Q. How will ancillary services be addressed in the new fifteen-minute market?

A. Ancillary services can also be awarded as a block schedule and will be considered to be self-provided in the fifteen-minute market for purposes of determining the financially binding ancillary services price. Currently, if the ISO dispatches contingency reserves on the interties, the energy schedule remains at the dispatched level for the remainder of the hour

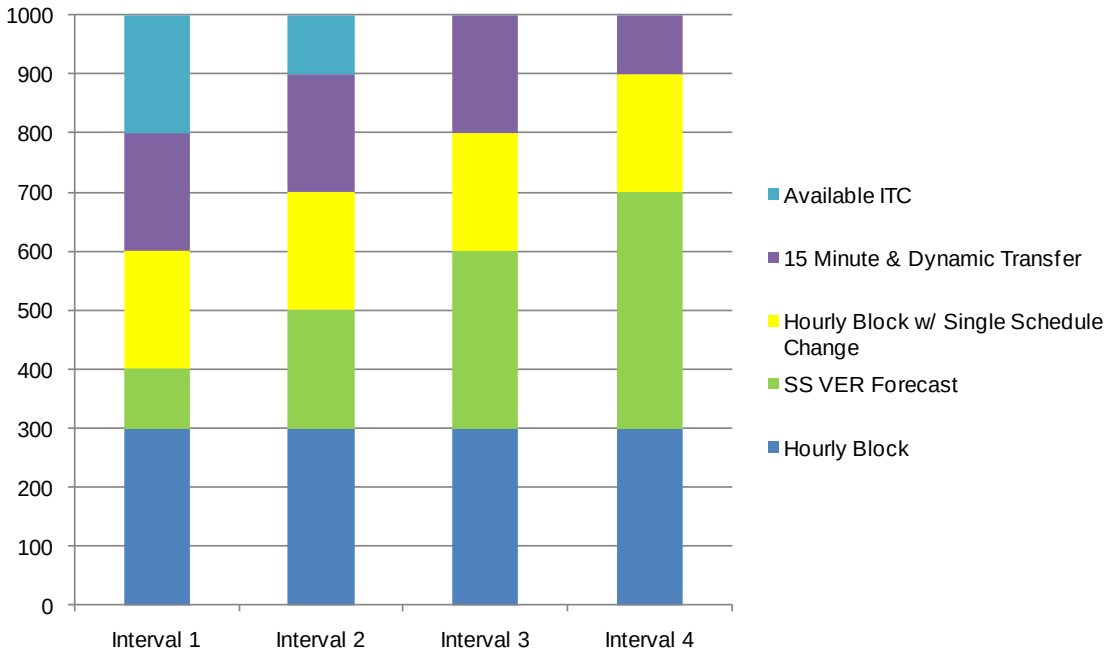
pursuant to WECC practice. The implementation of the ISO's new fifteen-minute market will not change this WECC practice. For example, assume a resource has an hourly block advisory energy schedule of 100 MW and a spinning reserve schedule of 50 MW. In the event that the spinning reserve was dispatched in interval 2, the energy schedule would increase to 150 MW, and the remaining intervals of the hour, including the remaining fifteen-minute markets and five-minute real-time dispatch intervals, will reflect a self-schedule of energy at 150 MW.

Q. Please provide an example of the acceptance of block schedules under the new hour-ahead scheduling process.

A. Figure 3 below illustrates how the new hour-ahead scheduling process will accept block schedules. In this example, the intertie has an import limit of 1,000 MW and different totals of economic bids are submitted in each 15-minute interval. The sum of economic bids that would clear if not limited by transmission capacity would be 800 MW in interval 1, 900 MW in interval 2, 1,000 MW in interval 3, and 1,100 MW in interval 4. Since the sum of economic bids that would clear is greater than the import limit, the full sum of economics bids that would clear cannot be awarded in interval 4. The hourly blocks (in blue) and hourly blocks with bids for single intra-hour schedule changes (in yellow) clear at the same MW quantity for each 15-minute interval – 300 MW for hourly blocks and 200 MW for hourly blocks with intra-hour schedule changes.

The variable energy resource's hourly forecast (in green) is 100 MW for interval 1, 200 MW for interval 2, 300 MW for interval 3, and 400 MW for interval 4. The economic bids that will participate in the fifteen-minute market and dynamic transfers (in purple) clear at 200 MW for the first three intervals but clear at 100 MW for the fourth interval since the import limit has been reached. Every resource can submit a transmission profile via its e-tag that exceeds its advisory schedule (*e.g.*, energy clearing the advisory hour-ahead scheduling process).

Figure 3



Q. Please describe the submission of e-tags and ISO approval of e-tags under the new hour-ahead scheduling process.

A. For each of the intertie bidding/scheduling options illustrated in Figure 3, the ISO would approve e-tags with transmission profiles that exceed the maximum projected 15-minute energy advisory schedule or hourly block award (if submitted with a single intra-hour change). This is so the ISO can dispatch these intertie resources with these e-tags in the fifteen-minute market above their projected 15-minute energy or hourly block awards. This may result in the ISO accepting e-tags with transmission profiles that in the aggregate exceed the transfer capacity of an intertie, but, just like today, in no case will the ISO accept e-tags that have energy schedules on e-tags and ancillary services awards that in the aggregate exceed the transfer capacity of an intertie.

These rules are illustrated in the following hypothetical example. Assume an intertie between the ISO and an adjacent balancing authority with a 1,000 MW transfer capacity and three intertie resources wish to use that transfer capacity to transmit their energy and ancillary services bids. The ISO would only accept e-tags that have energy schedules and ancillary services awards of up to 1,000 MW for the intertie, but would accept tags with transmission profiles that in total exceed 1,000 MW. For example, each resource could submit a 500 MW transmission profile along with energy bids up to this amount. If the three resources were to request a total of more than 1,000 MW of transmission, the ISO would allocate the

1,000 MW of transmission among the resources based on economic dispatch.

B. Fifteen-Minute Market Process

Q. Please summarize the new fifteen-minute market process.

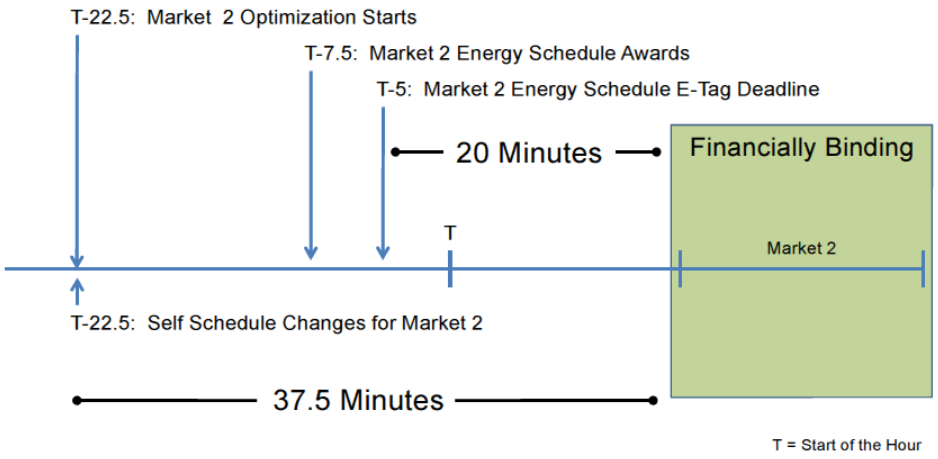
A. Under the new fifteen-minute market design, 15-minute energy schedules and ancillary services awards will be financially binding for imports, exports, internal resources, and load. The ISO will also liquidate convergence bids on a 15-minute basis. The ISO will leverage the existing real-time unit commitment process that currently co-optimizes energy and ancillary services but only results in financially binding unit commitment and ancillary services awards for internal resources. The current co-optimization calculates non-binding 15-minute energy schedules and LMPs. The fifteen-minute market will clear against the ISO's forecast of real-time demand.

Q. Please provide an overview of the real-time market intervals under the new market design.

A. In order to minimize seams issues with intertie transactions, the ISO will align the financially binding fifteen-minute market interval so that the e-tag deadline at 20 minutes in advance of flow can be met for the energy schedules dispatched by the fifteen-minute market runs. Aligning the fifteen-minute market interval to allow for e-tagging energy schedules for

the fifteen-minute markets requires that the ISO use the second 15-minute interval in RTUC for clearing the fifteen minute market, so that the ISO can issue awards at 22.5 minutes prior to the binding interval. This allows 2.5 minutes for intertie transactions to submit updated e-tags reflecting the binding energy schedule twenty minutes prior to flow. Only the energy portion of e-tags for energy schedule changes made in the fifteen-minute market needs to be updated, because market participants will presumably submit an e-tag with an hourly transmission reservation prior to the start of the fifteen minute market. Figure 4 below shows the second financially binding fifteen-minute market interval in a trading hour.

Figure 4 – 15-Minute Process for Real-Time Market



Q. How does the fifteen-minute market design account for coordination with neighboring WECC balancing authority areas?

A. There is no indication that there will be changes to the WECC interval ramping protocols in the near future. Currently hourly changes have a 20-

minute ramp and 15-minute changes will have 10-minute ramps. The ISO will use the appropriate ramp profile to ensure that awarded 15-minute schedules are feasible. As business processes evolve within WECC and the checkout of energy schedules becomes more automated, the ISO will evaluate if the fifteen-minute market could be pulled in closer to the binding interval if doing so is consistent with scheduling practices.

Based on discussions with neighboring balancing authorities and recognition of the likelihood that the 2.5 minute period between fifteen-minute market awards and the e-tagging deadline requires automation, the ISO will update energy schedules on e-tags for the fifteen-minute market awards within an hour. Neighboring balancing authority areas have stated that this will expedite their subsequent approval of the updated e-tags. This will help ensure that energy schedule changes based upon the results of the fifteen-minute market will be reflected in e-tags prior to the e-tagging deadline which is twenty minutes prior to flow. This is comparable to the interval for internal generation dispatches in which the ISO issues the dispatch 2.5 minutes prior to the start of the applicable dispatch interval. However, an important difference under the new market design is that the generation behind imports will have an additional fifteen minutes compared to internal generation before it has to change its output: the e-tagging deadline is at twenty minutes prior to flow while the ramp for intra-hour 15-minute schedule changes starts at five

minutes before flow. For multiple e-tags related to the same energy schedule, the ISO will adjust energy schedules on a *pro rata* basis.

Q. Does the ISO set the final energy schedule on the e-tag?

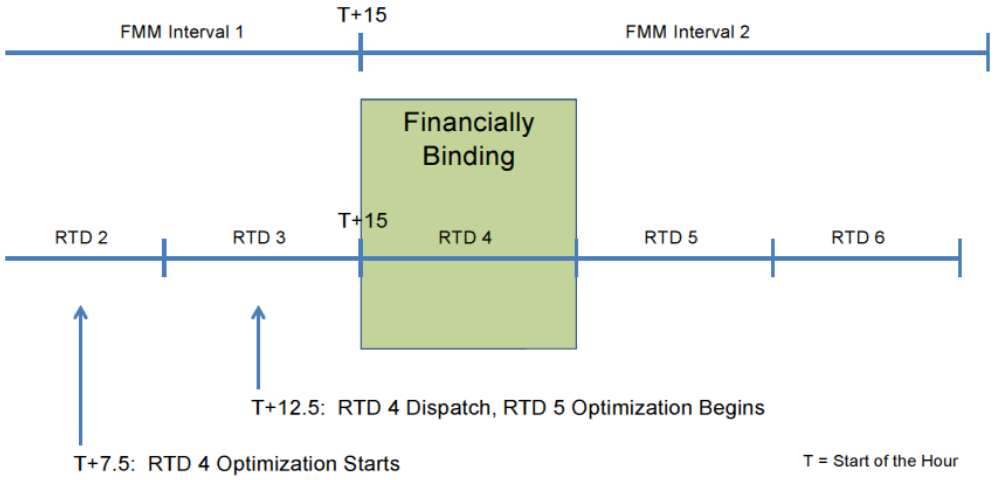
A. No. The scheduling coordinator can change the e-tag after the ISO performs the automated update I have described.

C. Real-Time Dispatch

Q. Please summarize the real-time dispatch process under the new market design.

A. The ISO is proposing no changes to the five-minute real-time dispatch intervals or business processes. The market optimization determines the financially binding dispatch and communicates to resources 2.5 minutes prior to the binding real-time dispatch interval. Figure 5 below shows the market intervals for the first real-time dispatch run in the binding fifteen-minute Interval 2 depicted in Figure 4. The five-minute real-time dispatch will continue to clear against the ISO's real-time demand forecast.

Figure 5 – Five-Minute Process for Real-Time Market



III. Settlements and Pricing Under the New Real-Time Market Design

Q. Please provide an overview of how energy will be settled for internal resources after the implementation of the fifteen-minute market and related market design changes.

A. Day-ahead energy schedules will continue to be settled at the day-ahead LMP. The difference between the fifteen-minute market energy schedule and the day-ahead energy schedule will be settled at the fifteen-minute market LMP. The difference between real-time dispatch energy dispatch and the fifteen-minute market energy schedule will be settled at the real-time dispatch LMP.

Instructed imbalance energy will be calculated every 15 minutes for the fifteen-minute market and every five minutes for the real-time dispatch.

The 15-minute instructed imbalance energy price will be based on a flat 15-minute energy schedule across the relevant 15-minute interval and settled at the 15-minute LMP. The five-minute instructed imbalance energy price will be based on the dispatch operating point, which is the dispatch trajectory between consecutive five-minute dispatches considering the applicable dynamic ramp rate, and it will be settled at the five-minute LMP. Uninstructed imbalance energy will be calculated every five minutes and settled at the five-minute LMP.

The ISO proposes to meter generation every five minutes. Currently the ISO receives five-minute meter data from internal generation, but then sums two five-minute intervals to align with the ten-minute settlement interval for purposes of calculating uninstructed imbalance energy. With the transition to five-minute meter data, there will be no reason to distinguish between tier-1 and tier-2 uninstructed imbalance energy; all uninstructed imbalance energy will be calculated and settled in one tier.

In addition, the addition of the fifteen minute market includes an additional real-time interval in which a resource may be economically dispatched. This is readily included in the bid cost recovery calculations by including in the real-time bid cost recovery energy market revenues and energy bid costs from both the fifteen-minute market and the real-time dispatch using the same hourly bid curve. There is no need to change the calculation of

the start-up and minimum load cost payments, which will continue to be paid based on their commitment in the real-time unit commitment interval.

In the case of export resources, the existing make-whole payments due to price corrections for export resources will also need to be provided for both 15-minute and, if applicable, five-minute LMP corrections. As part of the revised market design, the ISO adapted a component of the ISO's September 25, 2013 tariff amendment to implement phase 1 of the ISO's renewable integration market and market review enhancements ("RIMPR 1"). In that filing, the ISO proposed to include a performance metric to ensure resources do not deviate from ISO instructions for the purpose of expanding their bid cost recovery payments in a manner that is not consistent with the purpose of bid cost recovery under the ISO tariff. The performance metric was defined for the 10-minute settlement interval. With the movement to the five-minute settlement interval, the ISO is proposing to modify the applicable parameters to reflect the use of five-minute intervals instead of 10-minute intervals under the revised market design. Essentially, because moving to five-minute intervals doubles the number of intervals in the hour, the prior parameters are doubled to reflect this change.

Q. How will energy schedules for transactions over the interties be settled?

A. All intertie transactions will be settled in a manner consistent with settlement of transactions with internal resources. If a 15-minute self-schedule or awarded energy schedule for intertie transactions is not e-tagged at 20 minutes prior to flow, the deviation or operational adjustment will be settled at the real-time dispatch price in the same manner as internal generation deviations to 15-minute energy schedules. If the energy schedule for hourly block schedules is curtailed for physical reasons, the self-schedule for each of the fifteen-minute market intervals for that hour can be updated. If an outage or other schedule change (*e.g.*, a schedule that is affected by outages or changes in variable energy resources' output in other balancing authority areas, by priorities of transmission service using non-ISO transmission providers, or similar reasons) is known prior to the start of the 15-minute optimization, the 15-minute energy schedule will reflect the schedule change. This will avoid a deviation between the 15-minute energy schedules, which would be settled at the real-time dispatch price, but would be subject to the intertie schedules decline charge which I discuss below.

Q. Why is the ISO proposing a distinct 15-minute settlement as opposed to settlement based on the average of the prices over three five-minute intervals within a 15-minute period?

A. The RTUC market optimization uses 15-minute intervals and generates 15-minute LMPs. real-time dispatch market optimization uses five-minute

intervals and generates five-minute LMPs. Under the new market design, using quantities determined in the fifteen-minute market optimization but settling based on the average of the prices over three five-minute intervals from a subsequent market optimization would create mismatches between the quantities and settlement prices. Those inconsistencies would be comparable to the inconsistencies that have caused issues with the real-time imbalance energy offset charges, which I described earlier.

Q. Please explain why the ISO decided not to settle deviations between the fifteen-minute market and real-time dispatch at the "worse of" price.

A. Several stakeholders suggested that positive generation deviations would be paid the lower of the 15-minute price or the real-time dispatch price, and negative deviations would be charged the higher of the 15-minute price or the real-time dispatch price. This "worse of" pricing proposal was intended to encourage resources to follow the ISO's real-time dispatch since uninstructed deviations would never be profitable under such an approach. The ISO concluded that such an approach would be an unwarranted departure from the fundamental principle in LMP markets that deviations should be paid or charged at the price existing in the timeframe in which the deviation occurs. The ISO believes that market participants should gain experience with the new fifteen-minute market and that additional rules to address deviations from ISO dispatch under

the new market design, such as implementation of uninstructed deviation penalties, should only be considered if justified by actual operating experience under the new market design.

Q. Please describe the intertie schedules decline charge.

A. Under the new market design, block schedules will be accepted in the hour-ahead scheduling process, but the ISO will not establish financially binding prices for settlement purposes through that process as it does today. Therefore, there can be instances where a resource does not bear a financial consequence if it is unable to meet its advisory energy schedule. This can occur when an incremental export is constrained in the import direction, when an incremental import is constrained in the export direction, or when an import from a variable energy resource overstates its expected energy output.

Similar issues occur under the current hour-ahead scheduling process market design, since deviations or operational adjustments from the hourly HASP schedule are settled at the HASP price. In order to address potential gaming concerns, the ISO implemented the intertie schedules decline charge. The monthly threshold for the intertie schedules decline charge with regard to imports or exports is the highest of 300 MW or 10% of total imports or exports. The price that applies to the MW above the

threshold is the maximum of $10 or 50% of the hour-ahead scheduling process LMP.

Under the ISO's proposed real-time market changes, an intertie schedules decline charge, similar to the current HASP intertie schedules decline charge, will apply to various intertie schedules. The intent of this charge is to penalize energy schedules that are not delivered or variable energy resource forecasts that are over-stated but do not otherwise incur a financial obligation in the market for the undelivered energy. The proposed intertie schedules decline charge will apply to the different hourly block scheduling options as follows:

Hourly Block

- Imports and exports that receive an incremental real-time advisory schedule and that result from the acceptance of block schedules in the new hour-ahead scheduling process are subject to the intertie schedules decline charge to the extent the decline occurs prior to the start of the market run for the applicable 15-minute interval. This is because the resource would then be dispatched down prior to the 15-minute interval and the resource would not receive a financially binding dispatch despite reserving intertie capacity in the new hour-ahead scheduling process. The decline charge will not apply if the decline occurs after the start of the market run for the applicable 15-minute interval because in that case the resource will receive a financially binding fifteen-minute market dispatch and be subject to the real-time dispatch price for the undelivered portion.

- If a resource has a day-ahead schedule, any operational adjustment will be settled at the 15-minute price or five-minute price and the resource's schedule will not be subject to the decline charge.

Hourly Block with Schedule Change

- Imports and exports that receive an incremental real-time advisory schedule from the acceptance of block schedules in the new hour-ahead scheduling

process are subject to the intertie schedules decline charge to the extent the decline is made prior to the start of the market run for the applicable 15-minute interval. This is because the resource would then be dispatched down prior to the 15-minute interval and the resource would not receive a financially binding dispatch despite tying up intertie capacity in the hourly process. The decline charge will not apply if the decline is made after the start of the market run for the applicable 15-minute interval because in this case the resource will receive a financially binding 15-minute market dispatch and be subject to the real-time dispatch price for the undelivered portion.

- If the incremental import or export is schedule is curtailed through the fifteen-minute market, the resource is not subject to the decline charge for the 15-minute interval(s) where the resource follows the ISO instructions.

Variable Energy Resource Using Its Own Forecast

- To address concerns that variable energy resources will overstate their forecast in the new hour-ahead scheduling process and will "crowd out" hourly block schedules from conventional resources, imports from variable energy resources are subject to the intertie schedules decline charge to the extent the resource over-forecasts during the course of a calendar month.

- For each hour, the ISO will compare the maximum 15-minute financially binding schedule (submitted 37.5 minutes prior to flow) with the maximum 15-minute advisory schedule from the hour-ahead scheduling process in which block schedules will be accepted (based upon the hourly forecast received 75 minutes prior to flow). Over the course of a calendar month, positive deviations can offset negative deviations in monthly threshold calculations. Thus, if the maximum advisory schedule exceeds the actual financially binding schedule by the threshold over the course of the month, the hourly forecast has on average overstated the actual production and, as a result, has crowded out hourly block schedules that otherwise might have been awarded if the forecast used in the hourly process was not biased upward. This charge does not apply to variable energy resources that use the ISO's forecast.

Q. Please describe settlements of load under the new market design.

A. Both the fifteen-minute market and the real-time dispatch will clear against the ISO forecasted demand. Differences in load from day-ahead schedules will be settled at the hourly weighted average LMP of the

fifteen-minute market and the real-time dispatch by default load aggregation points. The LMPs will be weighted by the MW cleared in the two respective markets and will be bounded by the most extreme LMP from those relevant intervals.

The use of ISO load forecasts to determine the hourly weighted average price and price mitigation measures for extreme LMPs will result in certain uplifts that will need to be allocated to market participants in the form of a neutrality adjustment. Some stakeholders suggested that these neutrality charges should be allocated to all deviations from net load – the ISO load forecast less the variable energy resource forecast. The ISO has determined that such an approach would not be appropriate because variable energy resources are settled in the fifteen-minute market based upon their forecasted output. The additional costs associated with the hourly weighted average are only attributable to load that is metered hourly. The variable energy resource forecast error is settled correctly as deviations between the fifteen-minute market and the real-time dispatch. As a result, only the ISO load forecast results in the neutrality charge of the load settlement.

Q. How will load-following metered subsystems be settled under the new market design?

A. Load-following metered subsystems will be settled similar to how they are settled under the current market design. In the fifteen-minute market, load-following metered subsystems will need to balance their load and supply. In the real-time dispatch, the load-following metered subsystems must balance their load and supply in the five-minute interval within the established threshold or be subject to metered subsystems load-following deviation penalties. Similarly to internal generation, load-following metered subsystems settlement intervals will be changed from a 10-minute granularity to a five-minute granularity.

Q. Will the new market design create any new limitations for demand response?

A. No. Participating loads, proxy demand resources, and other dispatchable demand response will continue to have the opportunity to participate in the fifteen-minute market and the real-time dispatch.

Q. Will the introduction of the fifteen-minute market potentially cause uplift charges, because the fifteen-minute market will occur before the five-minute market?

A. The new fifteen-minute market will potentially cause uplift charges, but the ISO proposes measures to minimize them. The new market design addresses identified issues with settlement differences for interties, internal generation, and load. As discussed further by Mr. Cook, these

differences were exacerbated by convergence bidding and led to the suspension of virtual bidding on the interties. It is impossible to eliminate all real-time imbalance energy offset costs since not all energy can be settled through the market optimization. Load forecast error and uninstructed deviations from generation will continue to be settled but are not known when clearing the market. The revised market design includes price mitigation measures that will be used in determining the hourly settlement price of load to prevent a single load serving entity receiving a large financial impact due to small deviations.

Q. Does the ISO anticipate systematic price differences under the revised market design?

A. No. The most recent report on market issues and performance issued by the ISO's Department of Market Monitoring ("DMM") included an analysis of energy market performance in the third quarter of 2013.[1] The DMM's analysis shows that real-time pre-dispatch prices are higher than integrated forward market and real-time dispatch prices, and that there is good price convergence between the integrated forward market and the real-time dispatch. The real-time pre-dispatch energy schedules are not financially binding and transparent to market participants, and thus divergence between real-time pre-dispatch prices and integrated forward market or real-time dispatch prices does not result in uplift costs. The ISO

[1] The DMM's report is available on the ISO's website at http://www.caiso.com/market/Pages/MarketMonitoring/MarketIssuesPerfomanceReports/Default.aspx.

anticipates that the price convergence will continue under the new market design.

In addition, under the new market design, convergence bidding will be settled in real-time at the 15-minute market price, not the real-time dispatch price. This will improve convergence between the prices in the integrated forward market and the fifteen-minute market, which is where the majority of imbalance energy from day-ahead schedules will be settled. The real-time dispatch will settle only price differences between the fifteen-minute market and the real-time dispatch, whereas today, all price differences (except for intertie price differences) are settled at the real-time dispatch price.

Q. What measures is the ISO taking to mitigate any potential for systematic differences?

A. The same bids are used to clear the fifteen-minute market and the real-time dispatch. This provides consistency between both market optimizations as to the resources available to meet imbalance needs. Prior to implementation of the revised market design, the ISO will begin archiving the prices and schedules from the second real-time unit commitment interval and will analyze the correlation between real-time unit commitment prices and potential contributing factors for price divergence. The ISO currently monitors and analyzes price convergence

between the day-ahead market, hour-ahead scheduling process, and real-time dispatch. The ISO will continue to monitor and analyze convergence between all markets under the revised market design.

Q. Does the flexible ramping constraint cause uplift due to real-time imbalance energy offset?

A. No. The flexible ramping constraint ensures that sufficient resources are committed in the real-time unit commitment to reliably meet potential ramping needs in the real-time dispatch. The flexible ramping constraint is not enforced in the financially binding real-time dispatch interval to allow energy to be dispatched from resources meeting the flexible ramping constraint in the real-time unit commitment, but the constraint is enforced in advisory intervals to position resources to meet future real-time dispatch intervals. The ISO has been developing the flexible ramping product as the long-term solution to ensure that sufficient ramping capability is on-line and that will enforce a flexible ramping constraint in both the real-time unit commitment and the real-time dispatch. This will improve on the current constraint that the ISO only enforces in the real-time unit commitment. The ISO will continue to monitor the effectiveness of the flexible ramping constraint once the fifteen-minute market is implemented.

IV. Features of the New Market Design Specific to Variable Energy Resources

Q. Please describe the ISO's current participating intermittent resource program.

A. The ISO developed the participating intermittent resource program ("PIRP") to facilitate the initial integration of renewable resources into the ISO's markets. In return for providing meteorological data to allow production forecasting, PIRP resources were allowed to net uninstructed imbalance energy over the course of a month.

Currently each PIRP resource must submit as a real-time self-schedule the ISO hourly forecast generated 90 minutes prior to the hour to be eligible for monthly netting of uninstructed imbalance energy. This hourly forecast is used to establish instructed energy in real-time dispatch intervals, which is the five-minute real-time part of today's market in which the ISO dispatches resources, by dividing the total hourly forecast by twelve. If the PIRP resource does not submit the hourly forecast as a real-time self-schedule, the hour is excluded from monthly netting of uninstructed imbalance energy. If the PIRP resource does not have a day-ahead schedule (which often occurs), the resource's scheduled instructed energy output based on the hourly forecast is settled at the average hourly real-time dispatch price for energy at the relevant location.

Instructed energy is settled at the 10-minute weighted average of the two real-time dispatch intervals, but since PIRP instructed energy is flat for the hour, the price is equal to the average hourly real-time dispatch price. For non-PIRP resources (including eligible intermittent resources that have not signed up for the participating intermittent resource program), uninstructed energy is settled at the 10-minute average price of the two real-time dispatch intervals. For PIRP resources, the uninstructed imbalance energy is subsequently netted over the month and paid (or charged) the output-weighted average monthly LMP. Only internal resources are eligible to take part in the participating intermittent resource program.

Q. Why is the ISO proposing changes to the participating intermittent resource program?

A. The ISO believes that, with the improved opportunities for variable energy resources to schedule their production closer to real-time (as the result of a bid or self-schedule) under the proposed market design enhancements, it is appropriate to modify the participating intermittent resource program. Under the fifteen-minute market settlement, variable energy resources will now be able to secure a forward energy position in the fifteen-minute market, based upon a forecast received 37.5 minutes prior to flow. This 15-minute price should be less volatile than the real-time dispatch price because resource commitment decisions can be made, greatly reducing variable energy resources' exposure to price volatility.

Variable energy resources will only be subject to the real-time dispatch price for forecast error between the 15-minute schedule and real-time dispatch interval and for ramping between 15-minute schedules. This amount of energy subject to the real-time dispatch price will be significantly less than under the current market design in which all of the variable energy resource's output is subject to the real-time dispatch price (unless scheduled in the day-ahead market). With five-minute metering and if the resource elects to use five-minute forecast granularity, both instructed and uninstructed imbalance energy are settled at the same five-minute LMP.

Q. Please explain how the participating intermittent resource program will change under the new market design.

A. First, and most significantly, the ISO has determined that the additional real-time scheduling options available to variable energy resources along with the ability to submit economic bids to be dispatched down in real-time will eliminate the need for monthly netting of uninstructed imbalance energy. As explained below, the ISO's analysis of market data shows that the new market functionality will allow most variable energy resources to earn real-time market revenues that will more than offset the impact of eliminating hourly netting. Other PIRP changes include the following:

- PIRP participation will be identified in the ISO's master file. There will be no hourly option to be in or out of the participating intermittent resource program.

- Scheduling coordinators will not have to send back the ISO forecast, which will reduce scheduling delays and potential errors.

- Economic bids for all resources can be submitted hourly for use in the fifteen-minute market and the real-time dispatch to award an energy schedule or dispatch different than the resource's forecast.

- The participating intermittent resource program will use a forecast with a three-hour look-ahead and five-minute granularity.

- The 15-minute schedule will be the sum of the relevant three five-minute forecasts received 37.5 minutes prior to flow.

- The real-time dispatch instructed energy for the dispatch will be based on the relevant five-minute forecast received 7.5 minutes prior to flow.

- Real-time dispatch instructed energy deviations from the 15-minute schedule divided by three will be settled at the real-time dispatch LMP.

- Uninstructed imbalance energy will be the difference between the meter and the real-time dispatch instruction based upon the forecast from 7.5 minutes prior to flow and will settle at the real-time dispatch price.

Q. Please describe the different options for variable energy resources to use forecasts for scheduling under the new market design.

A. One benefit of the new market design is the similar treatment afforded internal and external variable energy resources. Variable energy resources will have the option to use the ISO forecast or their own forecast. If a variable energy resource elects to use its own forecast in the new hour-ahead scheduling process, it will be subject to the intertie schedules decline charge described above. There are no other settlement

differences between the use of the ISO forecast or the resource's forecast in the 15-minute market or the real-time dispatch.

The selection of whether a variable energy resource is using the ISO forecast or its own forecast will be documented in the resource's master file. The ISO's master file update process takes approximately 7 to 10 business days for changes to become effective in the market. In addition, the ISO is developing a certification process to approve the use of a variable energy resource's own forecast. The ISO will compare its forecast with the resource's forecast over time to determine which forecast is more accurate. The ISO will also look for instances of strategic forecasts to exploit differences between 15-minute and 5-minute prices. The ISO is seeking the authority to rescind the ability of a variable energy resource to use its own forecast if the resource's forecast is significantly less accurate than the ISO forecast over time. This authority addresses concerns raised by the Market Surveillance Committee and Department of Market Monitoring regarding the ISO's allowing variable energy resources to submit their own forecasts.

Q. Does the new market design provide variable energy resources with a greater ability to submit economic bids in real-time?

A. Yes. Economic bids from variable energy resources can protect against negative prices during periods of over-generation. Pursuant to a tariff

amendment pending before FERC, the ISO bid floor will be reduced from – $30/MWh to -$150/MWh in April 2014. The lower bid floors will provide additional incentives for variable energy resources to submit economic bids to ensure that their forecasts are only scheduled if the LMPs are greater than their bids. Further, economic bids will make variable energy resources eligible for bid cost recovery, which is not the case today for PIRP resources because they must self-schedule.

In the flexible ramping product stakeholder initiative, a key requirement for providing the flexible ramping down product is that the resource must participate in the market by submitting an energy bid to be used by the real-time dispatch. By fully participating in the market and providing the future flexible ramping product, variable energy resources will offset, at a minimum, the other costs associated with fully participating in the market.

The ISO is proposing comparable flexibility as part of the enhancements proposed to comply with Order No. 764. On an hourly basis, a variable energy resource that wishes to be economically dispatched below its forecast and in the future participate in the flexible ramping down product will provide an energy bid that will be used to clear in both the fifteen-minute market and five-minute real-time dispatch, along with the resource's ramp rate. In both markets, the ISO will utilize the resource's forecast or the ISO forecast as the upper bound for the energy dispatch

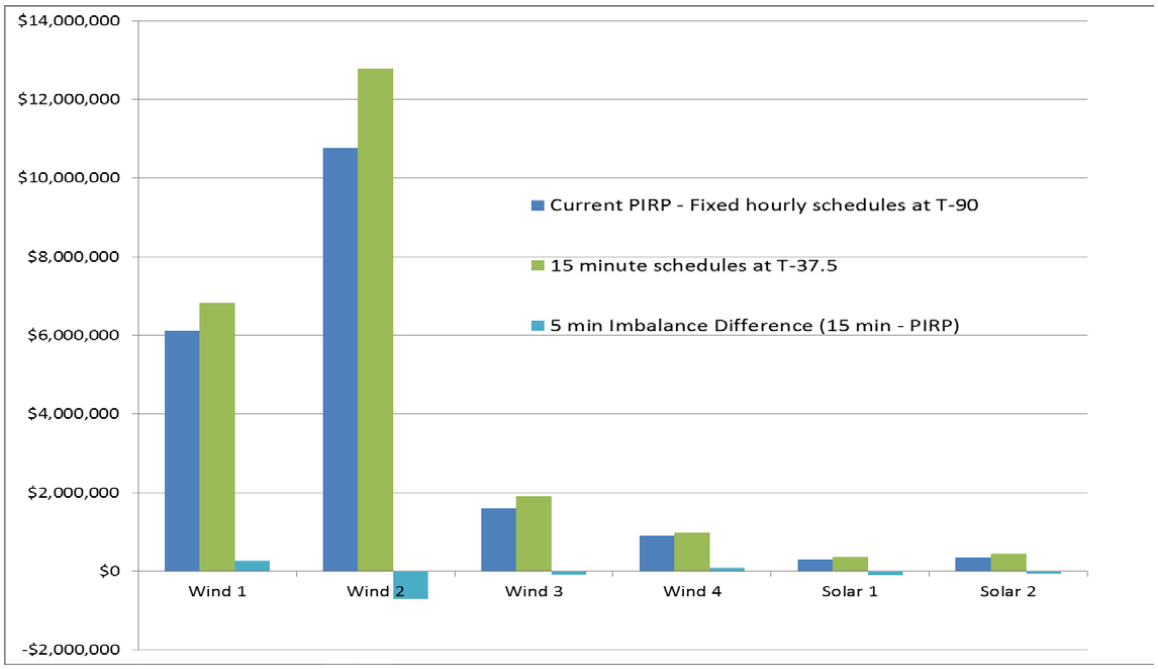
when considering the economic bid curve in the fifteen-minute market and five-minute real-time dispatch. In the future, a variable energy resource can be awarded flexible ramping down based upon the amount it can ramp down in five minutes, which is the same rule that applies to any other resource providing flexible ramping down. The settlement of energy dispatches and flexible ramping down awards in the fifteen-minute market and the real-time dispatch will be the same as for any other resource.

Q. Please describe the ISO's analysis of the benefits to variable energy resources of the new market design.

A. In the stakeholder process for the new market design, the ISO analyzed actual market data to compare the existing settlement provisions applicable to variable energy resources with the revised settlement provisions under the new market design. The ISO's analysis showed that the vast majority of variable energy resources will receive more real-time market revenues under the revised market design than they do currently. The analysis was based on the use of a persistence forecast that compared the results under the existing market design and the revised market design.[2] These results are shown in Figure 6 below.

[2] This information is available on the ISO website at: http://www.caiso.com/Documents/Board%204)%20decision%20on%20FERC%20order%20764%20market%20design%20changes.

Figure 6 – Real-time Market Revenue Comparison (July 2011 – June 2012)



Although the majority of intermittent resources can be expected to benefit from these market design changes, stakeholders have suggested that some older intermittent resources may be subject to operational or other limitations that prevent them from immediately benefitting from the market design enhancements. The ISO Governing Board determined that it was appropriate to approve protective measures that will ease the transition of these older intermittent resources to the new market design.

Q. Please describe the transitional protective measures proposed by the ISO.

A. The ISO's proposes protective measures to give certified PIRP resources utilizing older technology a three-year transition period so they can prepare to operate under the market design changes. The transition period for these resources will run three years from the implementation of the market design changes, or until a new bilateral agreement for power purchases is executed for the resource, whichever comes first. If a resource is certified as a PIRP resource and qualifies for the protective measures after the three-year transition period starts to run, the resource will be subject to the protective measures for the remainder of the transition period or until a new bilateral agreement for power purchases is executed, whichever comes first.

Q. What are the requirements to qualify for these protective measures?

A. To qualify for the protective measures, a participating intermittent resource must meet all of the following requirements:

(1) Either (a) or (b) must be the case for the resource:

(a) More than 50 percent of the resource must be composed of technology that is unable to curtail output and cannot be made to do so without significant investment. Resources that lack only dispatch, control, and telemetry or metering that require upgrades to be able to respond will not qualify. Resources that require production facility investments such as turbine replacement would qualify.

(b) The resource is subject to an existing bilateral agreement for power purchases that is in effect when the measures become effective and that prohibits the resource from curtailing its output in response to an ISO dispatch (not including times when the resource is ordered to curtail its output by the ISO or an affected utility distribution company for reliability reasons).

(2) The owner of the resource must be responsible for real-time energy settlement, either under its existing bilateral agreement for power purchases or because the resource is not subject to any such bilateral agreement and thus is subject to real-time imbalance energy settlement in the ISO market. Any bilateral agreement for power purchases must specify that the resource is directly or indirectly subject to real-time imbalance energy settlement in the ISO markets.

(3) During the three-year term of the transition period, the resource owner must agree to engage in a good faith effort to address the existing contractual limitations, or the resource owner must engage in a good faith effort to upgrade the resource so that it can address the physical limitations.

(4) The resource owner must sign an affidavit certifying the resource meets all of criteria (1) thorough (3) above as appropriate. The ISO will not be testing resource to evaluate the validity of their

statements. But the ISO will ask for authority to audit the parties for that limited purpose should the need arise.

Q. How will qualifying resources become subject to these protective measures?

A. Participating intermittent resources that believe they meet all the qualification requirements I have described above must request the transitional protective measures within 30 days of the implementation of the market design changes. Resources that qualify and select the settlement provisions applicable under the protective measures must remain under that settlement for the entire three-year transition period or until they enter into new bilateral agreements for power purchases, whichever comes first. The ISO will post on its website the requests received and the disposition of the requests. This will provide the necessary transparency so that market participants may evaluate the degree to which these measures are applied.

Q. Please describe the settlement rules that will be used for these transitional protective measures.

Participating intermittent resources that meet those requirements will be subject to a real-time market settlement under the market design changes that is similar to the existing settlement provisions applicable to

participating intermittent resources. Specifically, a resource that qualifies for and requests the protective measures will be settled as follows:

- An hourly schedule will be settled using a forecast from 90 minutes in advance of the applicable hour.
- The resource's hourly schedule based on that forecast will be settled at the simple average of the five-minute locational marginal prices.
- Deviations between the resource's actual energy output and the hourly schedule will be netted over each month. This amount will be settled at the output-weighted average of five-minute locational marginal prices over the month.
- The settlement of resources under the protective measures will be trued up in later settlements after the market design changes are implemented. Any financial adjustments will be subject to the FERC interest rate.

The difference between the real-time market settlement of any intermittent resource under the protective measures and the settlement that would have occurred under the market design changes will be allocated in the same manner as under the settlement methodology currently applicable to participating intermittent resources, *i.e.*, to net negative deviations. This amount may be a payment or a cost to net negative deviations.

Q. Does the ISO propose additional settlement measures to align settlement under the transitional protective measures as closely as possible with the existing settlement of PIRP resources based on monthly netting?

A. Yes. There are instances where a PIRP resource is its own scheduling coordinator and is subject to contractual provisions that require the

resource to use an inter-scheduling coordinator trade with the contractual counterparty based on the hourly forecast. Under the new fifteen-minute market, real-time inter-scheduling coordinator trades will be priced at the average of the relevant 15-minute LMPs (unless the resource makes the election described below). The ISO recognizes that this pricing may introduce settlement differences as compared with the current PIRP settlement methodology, because both hourly forecasted PIRP resources and inter-scheduling coordinator trades are currently settled at the average of the relevant 5-minute LMPs. To address these settlement differences, the ISO proposes that resources be allowed to elect to price their inter-scheduling coordinator trades at the average of the relevant 5-minute LMPs.

Q. Thank you. I have no further questions.

I, Donald Tretheway, affirm under penalty of perjury that the statements in this declaration are true and correct to the best of my knowledge, information, and belief.

Donald Tretheway

Executed this 26th day of November, 2013

Attachment K – Declaration of Gregory Cook

Real-Time Market Design Enhancements Related to Order No. 764

California Independent System Operator Corporation

November 26, 2013

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

California Independent System Operator Corporation	**)** **)**	**Docket No. ER14-____-000**

DECLARATION OF
GREGORY COOK
ON BEHALF OF THE
CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION

Q. Please state your name, title, and business address.

A. My name is Gregory Cook. I am employed as Director of Market Design and Regulatory Policy for the California Independent System Operator Corporation ("ISO"). My business address is 250 Outcropping Way, Folsom, CA 95630.

Q. Please describe your educational and professional background.

A. I received a Bachelor of Science degree in Electrical Engineering from New Mexico State University in 1990 and a Master of Business Administration degree concentrated in Regulatory Economics from New Mexico State University in 1993.

I have over twenty years of experience in the electric utility industry, working extensively in the area of competitive electric markets. Prior to joining the ISO, I worked at two investor-owned utilities as a Regulatory

Economist and was a Policy Advisor to the Public Utilities Commission of Nevada.

I began working at the ISO in 2000. My previous responsibilities at the ISO included managing the ISO's market monitoring team, which entailed monitoring and reporting on the performance of the ISO's energy and ancillary service markets. In 2005 I accepted the position of Manager, Market Design and Regulatory Policy. In this position I was responsible for leading the team that developed market design enhancements for the ISO's energy and ancillary service markets. In November 2009, I accepted my current position of Director of Market Design and Regulatory Policy.

Q. What are your current duties and responsibilities at the ISO?

A. My current duties and responsibilities include leading the team responsible for the evolution of the ISO's market design and infrastructure policy. My current efforts are focused on orienting the ISO's market structure to integrate large amounts of renewable resources and to remove barriers for new technologies including dispatchable demand response and storage resources. I am also responsible for advancing the ISO's infrastructure policies to facilitate the changing needs of the industry to ensure that adequate resources are available to maintain reliable grid operation and to ensure that new resources are efficiently interconnected to the ISO

system. In my current position I have led the development of several major design elements including the ISO's initial convergence bidding design, the ISO's proposal to suspend convergence bidding over intertie pricing points, and the current real-time market enhancements to comply with Order No. 764 and facilitate the effective participation of renewable resources.

Q. What is the purpose of your declaration?

A. I will discuss the ISO's proposal to reinstate convergence bidding on the interties between the ISO balancing authority area and neighboring balancing authority areas after the ISO has implemented market design changes that will enhance the ISO's real-time market and provide an option for market participants to schedule energy in 15-minute increments. First, by way of background, I will provide an overview of how convergence bidding works in the ISO markets and describe the two issues the ISO and market participants faced following the initial implementation of convergence bidding on the interties in February 2011. I will then discuss the stakeholder processes the ISO instituted to address these issues and the subsequent decision to discontinue convergence bidding on the interties effective as of November 28, 2011, until the ISO could develop a solution to these two issues through an appropriate stakeholder process.

Next I will discuss the comprehensive, long-term structural solution that the ISO and stakeholders developed to permit the reinstatement of intertie convergence bidding. I will explain how the structural solution will resolve both of the issues that required intertie convergence bidding on the interties to be discontinued. I will also describe the precautionary measures that will apply when convergence bidding on the interties is reinstated in order to prevent unintended adverse market outcomes.

I also will discuss the potential for "implicit" virtual bidding under the ISO's enhanced real-time market design and certain modifications to e-tagging rules the ISO is proposing to deter such implicit virtual bidding.

Lastly, I will address the interdependencies between the ISO's real-time market design enhancements proposed in this filing and other significant ISO market initiatives scheduled for 2014, and in particular the initiative to implement a new energy imbalance market for neighboring balancing authority areas.

The market design changes the ISO proposes in its filing, other than those related to the reinstatement of convergence bidding, are addressed by my colleague Donald Tretheway, Lead Market Design and Regulatory Policy Specialist for the ISO.

Q. Will you be using any specialized terms in your declaration?

A. Yes. Unless otherwise indicated, specialized terms in my declaration have the meanings set forth in the Master Definitions Supplement, Appendix A of the ISO tariff.

I. Background

Q. How does convergence bidding work in the ISO markets?

A. ISO market participants can hedge their market positions and manage their exposure to the differences between day-ahead and real-time prices by submitting purely financial bids – called virtual bids in the ISO tariff and sometimes also referred to as convergence bids. If a market participant's virtual bid is cleared in the day-ahead market, it is automatically liquidated with the opposite buy/sell position at the real-time price. Some of the main expected benefits of convergence bidding are improved convergence of day-ahead and real-time prices in the ISO's markets and more efficient dispatch of physical resources.

Q. Please describe the ISO's initial implementation of convergence bidding.

A. The ISO implemented convergence bidding in February 2011 at both internal nodes and intertie scheduling points. In order to address the potential exercise of market power or unintended market consequences during the initial period of convergence bidding implementation, the

Federal Energy Regulatory Commission ("FERC") approved the ISO's proposal to implement position limits on the megawatt volume of virtual bids that any one scheduling coordinator could submit at an individual node or intertie.

Q. Did issues arise with convergence bidding on the interties after the ISO implemented it?

A. Yes. Soon after convergence bidding went into effect, two issues arose with convergence bidding on the interties, despite the position limits and other measures approved by FERC to address potential market power and adverse market consequences.

Q. What was the first of those issues?

A. The first and most significant issue was that convergence bidders were able to take advantage of the fact that the ISO's real-time market structure currently includes both (1) an hour-ahead scheduling process that clears certain transactions in the hour-ahead time frame, and (2) a real-time market. Together, these two components of the current real-time market structure are sometimes referred to as the "separate settlement structure." Actual market data showed that the separate settlement structure in the real-time was inhibiting the intended market efficiencies associated with convergence bidding on the interties and causing adverse impacts on the

market through an increase in market uplifts and the distortion of market prices.

Q. Please explain why and how the current separate settlement structure had these adverse effects.

A. As I explained, convergence bidding involves placing purely financial bids at particular pricing nodes in the day-ahead market. If cleared in the day-ahead market, virtual supply and virtual demand bids settle first at day-ahead prices. They then are automatically liquidated with the opposite sell or buy position at the applicable hour-ahead scheduling process price for interties or real-time dispatch prices for internal nodes. The hour-ahead scheduling process is where all intertie bids submitted in real-time were cleared and priced. This process runs prior to the 5-minute real-time dispatch for internal resources. Interties currently require a separate scheduling process in real-time because their schedules need to be finalized and cleared with adjacent balancing authority areas well in advance of the applicable operating hour. The real-time dispatch is the five-minute real-time market in which the ISO establishes binding dispatch instructions and prices for internal resources. Shortly after convergence bidding was implemented, concern arose about the increased cost of balancing the real-time market and arriving at revenue neutrality. That cost is referred to as the real-time imbalance energy offset. The concern was that differences in the hour-ahead scheduling process prices and

real-time dispatch prices incented virtual bidding strategies that did not serve to converge day-ahead and real-time prices but contributed to the real-time imbalance energy offset costs allocated to measured demand. It was determined that this issue was symptomatic of a fundamental current market design shortcoming which requires settlement of intertie transactions in the hour ahead scheduling process while internal supply and demand are settled later in the real-time dispatch.

Q. What was the second issue that arose with the implementation of convergence bidding on the interties?

A. The second and less significant issue that arose with convergence bidding on the interties was that the use of two software constraints (a physical and also a physical and virtual constraint) in the day-ahead market periodically caused market clearing prices on the interties to be inconsistent with the bid prices offered by a physical exporter or importer. This second issue was separate from and unrelated to the first issue discussed above.

Q. Did the ISO institute stakeholder initiatives to address these issues?

A. Yes. Even before the implementation of convergence bidding in February 2011, the ISO was discussing with stakeholders options to improve pricing on the interties and to address issues with the differences in prices

between the hour-ahead scheduling process and the real-time market under the separate settlement structure.

In April 2011 the ISO commenced the Real-Time Imbalance Energy Offset (2011) initiative, which the ISO established to evaluate and consider measures to address continued increases in real-time imbalance energy offset charges caused by differences between the hour-ahead scheduling process prices for convergence bidding transactions on the interties and the real-time dispatch prices for internal convergence bidding transactions (*i.e.*, the first issue discussed above). A second initiative begun in April 2011 was called Price Inconsistency Caused by Intertie Constraints, which the ISO established to address instances where physical imports and exports might clear inconsistent with their bid prices in the day-ahead market due to the enforcement of dual constraints to accommodate virtual bidding on the interties (*i.e.*, the second issue discussed above).

The ISO then combined those two stakeholder initiatives. After considering various alternative proposals in the combined initiative, the ISO concluded that discontinuing convergence bidding on the interties was justified, at least until a comprehensive market redesign solution could permit the ISO to address issues related to the existing design of the hour-ahead scheduling process and real-time market. Specifically, the ISO determined that a single settlement timeframe for interties and internal supply and demand would be needed to resolve the structural

issues that were afflicting convergence bidding on the interties. If the settlement timeframes of the real-time market could be resolved so that there is a common clearing price for intertie schedules and internal resources, convergence bidding at the interties could be reinstated.

Q. Did the ISO present these conclusions to FERC?

A. Yes. In September 2011, the ISO filed a tariff amendment requesting authorization to discontinue convergence bidding on the interties effective as of November 28, 2011. FERC accepted and suspended the tariff amendment for a nominal period, effective November 28, 2011 as requested by the ISO, and made its acceptance subject to the outcome of a technical conference and a further FERC order. At the February 2012 technical conference and in subsequent filed comments, the ISO provided further documentation that supported discontinuing convergence bidding on the interties. On May 2, 2013, FERC issued an order conditionally accepting the ISO's proposal to discontinue intertie convergence bidding.

Q. What additional steps did the ISO undertake to address the issues that led to suspension of convergence bidding on the interties?

A. In late 2011, the ISO established a new stakeholder initiative, called Intertie Pricing and Settlement, to determine long-term solutions to address the real time imbalance energy offset and pricing inefficiencies between the hour-ahead scheduling process and the real-time market.

Following the issuance of Order No. 764, the ISO determined that the directives in that order provided an opportunity for market design enhancements that will more effectively and efficiently integrate a large amount of variable energy resources into the resource fleet serving ISO customers as well as address ongoing concerns with intertie pricing. The ISO therefore initiated a new stakeholder process, called FERC Order No. 764 Market Changes, in which the ISO and stakeholders developed the market design changes addressed in the declarations of myself and Mr. Tretheway.

II. Reinstatement of Convergence Bidding on the Interties

Q. Have the ISO and stakeholders found a solution to the issues that required convergence bidding on the interties to be discontinued?

A. Yes. The ISO and stakeholders have developed a comprehensive, long-term structural solution to intertie pricing issues that, among other things, will permit the reinstatement of intertie convergence bidding.

Q. Please describe the solution.

A. As part of the market design enhancements proposed in the ISO's filing, convergence bids at both internal nodes and the interties will be settled at the average of the four fifteen-minute market prices for the applicable trading hour in the same market optimization, consistent with the use of

fifteen-minute market prices under the market design changes discussed by my colleague Mr. Tretheway.

Q. How will these market design enhancements address the first of the two issues with convergence bidding on the interties that you described earlier?

A. Once the current separate settlement structure is supplanted by the revised market structure, supply and demand on the interties and internal nodes will be settled in the same timeframe making it no longer profitable to offset virtual supply bids on the interties with virtual demand bids. As a result, the market inefficiencies associated with the current hour-ahead scheduling process and real-time price divergence resulting in real-time imbalance energy offset charges formerly attributable to such offsetting – *i.e.*, the first issue I described earlier – will be eliminated.

Q. How will these market design enhancements address the second of the two issues with convergence bidding on the interties?

A. Under the revised real-time market design, the ISO will only enforce in the integrated forward market the constraint that considers both physical and virtual intertie transactions.

However, the ISO also recognizes that enforcing only this constraint could result in physical schedules exceeding an intertie's capacity, since a

virtual schedule can provide counter-flow to relieve congestion. Such an outcome could be problematic because the ISO must comply with the requirement of the Western Electricity Coordinating Council ("WECC") requirement that transmission service providers accept e-tags only up to an intertie's capacity.

Q. How does the ISO propose to prevent that outcome from occurring?

A. To prevent that outcome, the ISO proposes to accept e-tags in economic merit order of the cleared intertie bids up to an intertie's capacity. Any cleared intertie bids above that amount will not be allowed to e-tag prior to the start of the real-time market. Since virtual intertie schedules are only considered by the day-ahead market, the physical intertie schedules produced by the real-time market will always be within each intertie's capacity. Consequently, the ISO will be able to accept e-tags for all physical intertie schedules by WECC's real-time e-tag deadline of 20 minutes prior to the operating interval.

Q. Does the ISO propose any precautionary measures for reinstating convergence bidding on the interties?

A. Yes. Although the ISO anticipates that the proposed structural solution will address the two issues discussed above and permit a successful reintroduction of convergence bidding on the interties, the ISO is also mindful of the need to proceed carefully given the need for market

participants and the ISO to gain experience with the other significant market design changes proposed in the ISO's filing.

To address concerns of many stakeholders over potential and unforeseen adverse consequences if convergence bidding on the interties is implemented at the same time the market is gaining experience with these other significant design changes, the ISO proposes to implement the real-time market design changes 12 months before the ISO reinstates convergence bidding on the interties. This implementation schedule will provide a "shakeout" period during which the ISO and market participants will be able to observe the operation of the new fifteen-minute market under various seasonal conditions.

Q. Does the ISO propose any other precautionary measure?

A. Yes. As another precautionary measure, the ISO proposes to phase in the reinstatement of convergence bidding on the interties through the use of gradually increasing position limits, which will limit the megawatt quantity of convergence bids that may be submitted by a scheduling coordinator to a specified percentage of the intertie transfer capability. Specifically, the ISO proposes the following schedule for phasing in the reinstatement of convergence bidding on the interties:

- Intertie position limits of 5 percent will apply for the first eight months after reinstatement of convergence bidding on the interties (*i.e.*, from April 1, 2015 to November 30, 2015).

- Intertie position limits of 25 percent will apply for the ninth through the twelfth months after reinstatement of convergence bidding on the interties (*i.e.*, from December 1, 2015 to March 31, 2016).

- Intertie position limits of 50 percent will apply for the thirteenth month through the sixteenth months after reinstatement of convergence bidding on the interties (*i.e.*, from April 1, 2016 to July 31, 2016).

- No intertie position limits will apply starting in the seventeenth month after reinstatement of convergence bidding on the interties (*i.e.*, August 1, 2016 and afterwards).

Q. Are these percentages and time periods the same as the percentages and time periods that applied to the initial implementation of convergence bidding on the interties?

A. Yes. These percentages and time periods for the position limits applicable to the gradual reinstatement of convergence bidding on the interties are the same as the percentages and time periods that FERC authorized when it approved the original implementation of convergence bidding on the interties.

Like the intertie position limits that were previously in effect, the position limits for the reinstatement of intertie convergence bidding are intended to serve as an additional safety net to prevent unforeseen and unintended market outcomes. Further, it is appropriate for the ISO to be cautious by gradually implementing convergence bidding on the interties. Additional caution is also justified given the total size of intertie transactions. Such an approach proved successful under the initial implementation of convergence bidding as the intertie limits prevented the unforeseen

market inefficiencies described earlier in my testimony from being exploited on a much larger scale. Thus, these same percentage limits provide a prudent path to smooth the transition to full reinstatement of convergence bidding on the interties.

III. Other Virtual Bidding Issues Related to the Revised Market Design

Q. Will the new market design include an option for explicit virtual bidding between the new fifteen-minute market and the five-minute real-time dispatch interval?

A. No. Unlike the day-ahead market, load will not be able to economically bid in the new fifteen-minute market, and thus it would be inappropriate to allow virtual demand to bid in the fifteen-minute market. In addition, the ability for physical resources to update their 15-minute schedule every 15 minutes reduces the duration a resource is exposed to five-minute deviations for an outage.

Q. In determining whether to reinstate convergence bidding on the interties, did the ISO consider the risks associated with "implicit" virtual bidding between the fifteen-minute market and the five-minute real-time dispatch interval under the new market design?

A. Yes. The ISO notes, however, that the five-minute market interval for the real-time dispatch minimizes potential "implicit" virtual bidding on the interties between the fifteen-minute market and the five-minute real-time

interval. The ISO believes that intertie resources may not e-tag their energy schedules awarded in the fifteen-minute market so that they will be settled at a lower real-time dispatch price for their deviations. As discussed in the declaration of Mr. Tretheway, the fifteen-minute market schedule is determined at 22.5 minutes prior to the start of the first binding real-time dispatch interval. Therefore, a market participant submitting an intertie schedule would not have visibility to actual real-time dispatch pricing as it is published 2.5 minutes prior to the binding interval before the e-tagging deadline of 20 minutes prior to the binding real-time dispatch interval. Based on the historical data provided, no analysis has concluded that there is a predictable price difference. The ISO will monitor for potential implicit virtual bidding and if this behavior results in reliability issues or market inefficiencies the ISO would consider remedial measures such as an uninstructed deviation penalty.

Q. Does the new market design include any changes to the ISO's current e-tagging rule to deter "implicit" virtual bidding on the interties?

A. Yes. An intertie transaction must be e-tagged at the time of the new hour-ahead scheduling process for an intertie transaction originally scheduled in the day-ahead market to be bought back at a profit in the real-time market. Under the current market design, an e-tag must be submitted at some point before the current hour-ahead scheduling process but the e-

tag is not required to be maintained through the hour-ahead scheduling process. Thus, the e-tag could be established before the hour-ahead scheduling process but then un-tagged. The new market design, however, will require the e-tag to be maintained through the hour-ahead scheduling process. This will help to prevent "implicit" virtual bidding on the interties.

IV. Interdependencies between the Revised Real-Time Market Design and Other Significant Market Initiatives

Q. Please address any interdependencies between the new real-time market design and other significant market initiatives being undertaken by the ISO.

A. One of the most significant market initiatives being undertaken by the ISO and its stakeholders in the next year is the development and implementation of an energy imbalance market ("EIM") that will allow balancing authorities throughout the West to voluntarily participate in a real-time imbalance energy market operated by the ISO. EIM is scheduled to become operational in October 2014. The EIM design and software implementation plan will build on the new fifteen-minute market and revised real-time market design proposed in the ISO's filing. The ISO determined that it would not be appropriate to develop EIM based on the current real-time market design platform given the intertie pricing issues with the current market design and the many benefits to market

participants that will come with the new real-time market design. As a result, if FERC were to reject the revised real-time market design or require significant modifications to the revised real-time market design it would have a substantial adverse impact on the schedule and implementation plan for EIM.

In addition, on September 25, 2013, the ISO filed proposed tariff revisions to implement phase 1 of the ISO's renewable integration market and market review enhancements ("RIMPR 1") which includes the separation of bid cost recovery settlement between the day-ahead market and the real-time market. The EIM design is also dependent on FERC acceptance of this change. Significant changes to either the RIMPR 1 design proposal or the revised real-time market design proposal could potentially delay the implementation of EIM by a year or longer.

Q. Thank you. I have no further questions.

I, Gregory Cook, affirm under penalty of perjury that the statements in this declaration are true and correct to the best of my knowledge, information, and belief.

Gregory Cook

Executed this 26th day of November, 2013

Attachment L – List of Key Dates in Stakeholder Process

Real-Time Market Design Enhancements Related to Order No. 764

California Independent System Operator Corporation

November 26, 2013

ATTACHMENT L

List of Key Dates in Order No. 764 Stakeholder Process

Date	Event/Due Date
October 9, 2012	ISO announces launch of new stakeholder process to develop real-time market design enhancements related to Order No. 764
October 23, 2012	ISO issues paper entitled "FERC Order 764 Compliance – 15-Minute Scheduling and Settlement Straw Proposal"
October 30, 2012	ISO hosts stakeholder conference call that includes discussion of ISO paper issued on October 23 entitled "FERC Order 764 Compliance – Implementation of 15-Minute Scheduling and Settlement," and presentations on related ISO analyses
November 16, 2012	Due date for written stakeholder comments on matters discussed on October 30 conference call
December 14, 2012	ISO issues matrix of stakeholder comments submitted on November 16 and ISO responses to the comments
December 18, 2012	ISO hosts stakeholder conference call that includes discussion of stakeholder comments submitted on November 16
January 8, 2013	Due date for written stakeholder comments on matters discussed on December 18 conference call
February 5, 2013	ISO issues paper entitled "FERC Order 764 Compliance – 15-Minute Scheduling and Settlement Revised Straw Proposal"
February 8, 2013	ISO issues matrix of stakeholder comments submitted on January 8 and ISO responses to the comments
February 12, 2013	ISO hosts stakeholder conference call that includes discussion of ISO paper issued on February 5
February 26, 2013	Due date for written stakeholder comments on matters discussed on February 12 conference call
March 26, 2013	ISO issues paper entitled "FERC Order 764 Compliance – 15-Minute Scheduling and Settlement Draft Final

Date	Event/Due Date
	Proposal”
April 1, 2013	ISO issues matrix of stakeholder comments submitted on February 26 and ISO responses to the comments
April 2, 2013	ISO hosts stakeholder conference call that includes discussion of ISO paper issued on March 26
April 16, 2013	Due date for written stakeholder comments on matters discussed on April 2 conference call
April 24, 2013	ISO issues paper entitled “FERC Order 764 Compliance – 15-Minute Scheduling and Settlement Addendum to Draft Final Proposal”
May 1, 2013	ISO hosts stakeholder conference call that includes discussion of ISO paper issued on April 24
July 26, 2013	ISO issues paper entitled “FERC Order 764 Market Changes – Intermittent Resource Protective Measures Straw Proposal”
August 2, 2013	ISO hosts stakeholder conference call that includes discussion of ISO paper issued on July 26
August 9, 2013	Due date for written stakeholder comments on matters discussed on August 2 conference call
August 15, 2013	ISO issues paper entitled “FERC Order 764 Market Changes – Intermittent Resource Protective Measures Draft Final Proposal”
August 22, 2013	ISO hosts stakeholder conference call that includes discussion of ISO paper issued on August 15
August 29, 2013	Due date for written stakeholder comments on matters discussed on August 22 conference call
October 4, 2013	ISO issues draft tariff language to implement FERC Order 764 market changes
October 8, 2013	ISO issues draft tariff language to implement changes to *pro forma* large generator interconnection agreement
October 15, 2013	Due date for written stakeholder comments on draft tariff language issued on October 4 and 8

Date	Event/Due Date
October 21-22, 2013	ISO hosts stakeholder conference call that includes discussion of draft tariff language issued on October 4 and 8
October 30, 2013	ISO issues revised draft tariff language to implement FERC Order 764 market changes
November 6, 2013	ISO hosts stakeholder conference call that includes discussion of revised draft tariff language issued on October 30
November 12, 2013	Due date for written stakeholder comments on revised draft tariff language issued on October 30
November 14, 2013	ISO issues draft tariff language to implement transitional protective measures for participating intermittent resources
November 18, 2013	ISO hosts stakeholder conference call that includes discussion of stakeholder comments provided on November 12
November 20, 2013	ISO issues final draft tariff language to implement FERC Order 764 market changes; ISO issues matrix of stakeholder comments submitted on October 15 and November 12, and ISO responses to the comments; due date for written stakeholder comments on draft tariff language issued on November 14
November 21, 2013	ISO hosts stakeholder conference call that includes discussion of draft tariff language issued on November 14
November 22, 2013	ISO hosts stakeholder conference call that includes discussion of final draft tariff language issued on November 20
November 25, 2013	ISO hosts stakeholder conference call that includes discussion of changes to *pro forma* large generator interconnection agreement

Attachment M – Summary of Comments Submitted in Stakeholder Process

Real-Time Market Design Enhancements Related to Order No. 764

California Independent System Operator Corporation

November 26, 2013

Attachment A

Stakeholder Process: FERC Order No. 764 Market Design Changes

Summary of Submitted Comments

Stakeholders submitted four rounds of written comments to the ISO on the following dates:

- Round One, 11/16/12
- Round Two, 01/08/13
- Round Three, 02/26/13
- Round Four, 04/16/13

Stakeholder comments are posted at
http://www.caiso.com/Documents/FERC%20Order%20No%20764%20market%20changes%20-%20papers%20and%20proposals%7CStakeholder%20comments

Other stakeholder efforts include:

- Stakeholder Meeting, 10/30/12
- Stakeholder Conference Call, 12/18/12
- Stakeholder Meeting, 02/12/13
- Stakeholder Meeting, 04/02/13
- Stakeholder Conference Call, 05/01/13

	Management Proposal: 15-Minute Settlement of Intertie Transactions			
	Intertie Scheduling Options and Timeline	**No Price Guarantee for Hourly Fixed Schedules**	**e-Tag Energy Schedule Updated by ISO**	**RTD Price for 15-Minute Deviations**
APS	Oppose Hourly schedule process should remain in addition to 15-minute market. Risk shifted to imports/exports will reduce hourly liquidity. Allow generators the ability to revise bids and schedules intra-hour versus 75 minutes prior to operating hour.	Oppose Not willing to take on the additional price risk, particularly when other means of buying and selling hourly energy through traditional bilateral contracts across WECC exist.	No Comment	No Comment
Brookfield	Conditional Support the general direction proposed by the ISO to promote a 15-minute market throughout the West.	Oppose Bid cost recovery for hourly fixed schedules should be retained for 18 months to allow time for 15-minute market to develop.	No Comment	Support
CalWEA	Support Start of 15-minute market should be shortened from T-37.5 minutes when supported by WECC.	No Comment	No Comment	No Comment
CPUC	No Comment	Supports Better aligns incentives to lead	No Comment	Oppose Potential implicit virtual bids undermine market certainty.

	Management Proposal: 15-Minute Settlement of Intertie Transactions			
	Intertie Scheduling Options and Timeline	**No Price Guarantee for Hourly Fixed Schedules**	**e-Tag Energy Schedule Updated by ISO**	**RTD Price for 15-Minute Deviations**
		to accurate market prices by having those who can build the risk premium into a bid price.		
Iberdrola	Support Promotes 15-minute market in the West and shares the concern that absent proper incentives this new market is unlikely to develop.	Conditional Concerned that some adjacent balancing authorities will not make the required changes to processes and infrastructure to enable entities to fully participate in the15-minute market.	No Comment	No Comment
Morgan Stanley	Support ISO moving to 15-minute markets and settlements can help stimulate faster evolution of other balancing authorities to similar practices, an evolution they find highly desirable.	Support Lack of price certainty at interties will increase the bid/ask spread and may reduce liquidity. However, we do not regard lack of price guarantee omission as a fatal flaw.	No Comment	Support
NRG	Support	Support Providing price guarantee for	Support	No Comment

	Management Proposal: 15-Minute Settlement of Intertie Transactions			
	Intertie Scheduling Options and Timeline	**No Price Guarantee for Hourly Fixed Schedules**	**e-Tag Energy Schedule Updated by ISO**	**RTD Price for 15-Minute Deviations**
	Both interties and internal resources will participate on an equal basis. The current problematic and discriminatory hour-ahead scheduling process cannot be eliminated quickly enough.	hourly intertie schedules would retain a preferential and discriminatory settlement that will discourage parties from expeditiously transitioning to 15-minute intertie scheduling.		
PG&E	Support The economic fixed scheduling functionality should sunset after an appropriate but minimal transition window, is prudent.	Support Intertie rules should encourage participation in the 15-minute market rather than the status quo. Providing price guarantee creates clear gaming opportunities that should not be allowed.	Support Addresses a key implementation concern raised earlier by stakeholders	Conditional See merit in future discussions on clearer protections, e.g. worse-of pricing, against willful deviations, if appropriate.
Powerex	Support Commends the ISO for offering a myriad of flexible scheduling options that should go a long way towards increasing the intra-hour flexibility offered from the interties.	Support Price guarantee may cause market inefficiencies and substantial unintended consequences.	Support	No Comment
SCE	Support Provides more options than any other WECC balancing authority. Such a design structure is the foundation on which market liquidity can be observed due to the accommodating nature of the	Support Price guarantee for hourly fixed transactions would go against Order No. 764 by transferring risk to load via market uplifts.	Support The ability to opt out on an hourly basis is available to market participants.	Oppose Implement a “worse-of” pricing mechanism or a decline charge for 15- minute participants that do not deliver.

	Management Proposal: 15-Minute Settlement of Intertie Transactions			
	Intertie Scheduling Options and Timeline	**No Price Guarantee for Hourly Fixed Schedules**	**e-Tag Energy Schedule Updated by ISO**	**RTD Price for 15-Minute Deviations**
	framework.			
SDG&E	Support A significant step forward in addressing several major problems with the current markets.	Support	No Comment	No Comment
Six Cities	Support	Support	No Comment	Oppose Inadequate measures to discourage deviations from the ISO's dispatch instructions.
WPTF	Conditional Concerned that neighboring balancing authorities will not be able to support a robust 15-minute market.	Oppose Price guarantee for fixed hourly schedules should be retained for 18 months to allow time for 15-minute market to develop.	No Comment	Supports
Management Response	**The proposed market design enables 15-minute scheduling across the interties in order to comply with FERC Order No. 764. The scheduling options provided support hourly fixed schedules, 15-minute scheduling and dynamic transfers consistent with WECC business practices and e-Tagging timelines. Not providing price guarantees to hourly fixed schedules will result in prices that reflect their value and incentivize the movement to 15-minute intertie scheduling. The mechanisms for ensuring dispatch instructions are consistent with the existing policies which have been in place since the 2009 market redesign (MRTU). The proposed design changes result in all market participants being settled comparably.**			

	Management Proposal: Convergence Bidding on Interties			
	Reinstatement	Intertie Position Limits	Resolution of Dual Constraint	No Convergence Bidding between 15-Minute Market and RTD
CDWR	Oppose Only after the one year minimum observation period has passed should a stakeholder process be started to evaluate the benefits of reinstating intertie convergence bidding.	No Comment	No Comment	Support
CPUC	Conditional Concerned about the reinstatement of convergence bidding on the interties. ISO should monitor for potential gaming.	Support Position limits necessary.	No Comment	No Comment
Morgan Stanley	Support	Support Position limits "default" actions, with phase-in of less restrictive limits only able to be delayed upon discovery of problematic evidence.	Support A creative and sound solution.	No Comment
NRG	Support	Conditional Looks forward to those limits	Support	No Comment

	Management Proposal: Convergence Bidding on Interties			
	Reinstatement	Intertie Position Limits	Resolution of Dual Constraint	No Convergence Bidding between 15-Minute Market and RTD
		automatically increasing on the schedule proposed.		
PG&E	Oppose Activation of convergence bidding on the interties simultaneously with Order No. 764 changes is inappropriate, risky, and unnecessary. At a minimum, the ISO should wait 120 days after Order No. 764 and the EIM have been implemented to ensure the market functions properly such that virtual bidding will improve market efficiency.	Support Limits buffer against excessively rapid increases in uplift charges.	Conditional ISO should commit to monitor liquidity effects in the integrated forward market.	No Comment
Powerex	Oppose ISO should commence a separate stakeholder process to review convergence bidding more holistically in its markets.	Oppose Intertie-specific limits will hinder the important ability of market participants to respond to (and eliminate) price anomalies.	Support But, believes these schedules that are allowed to e-tag day ahead, must also be obligated to e-tag day-ahead - not given the option to e-tag day ahead.	Support
SCE	Oppose ISO modeling of the system	Conditional Support Intertie convergence bidding has not been considered within the energy imbalance market	Oppose Physical and convergence bids are	Support

	Management Proposal: Convergence Bidding on Interties			
	Reinstatement	Intertie Position Limits	Resolution of Dual Constraint	No Convergence Bidding between 15-Minute Market and RTD
	between the day-ahead and real-time market runs can produce price divergence that makes convergence biddings profitable. The profits are funded through uplifts to load. This current structure is unjust and unreasonable and must be remedied before any attempt to address intertie convergence bidding implementation.	framework with no demonstration of how these changes will interact or whether they will even perform as intended.	not fungible in the ISO's proposal which may threaten intertie liquidity.	
SDG&E	Oppose Recommends the ISO conduct further analysis and comprehensively vet appropriate protections in a separate initiative.	Oppose There must be defined metrics and triggers, not a rigid timeframe for gradually increasing convergence bidding position limits	No Comment	No Comment
Six Cities	Oppose Should not return simultaneously with the adoption of the 15-minute scheduling processes.	No Comment	No Comment	Support
WPTF	Supports	Oppose Firm timeline is important for establishing full convergence	No Comment	No Comment

	Management Proposal: Convergence Bidding on Interties			
	Reinstatement	Intertie Position Limits	Resolution of Dual Constraint	No Convergence Bidding between 15-Minute Market and RTD
		bidding at the interties, however, there is no justification for delaying convergence bidding at the interties for 12 months.		
Management Response	**By aligning the convergence bidding real-time settlement of intertie schedule points and internal nodes to the 15-minute market, the fundamental market inefficiency which led to the suspension of convergence bidding on the interties has been addressed. The resolution of the dual constraint issue addresses the previously observed price inconsistencies for physical imports and export. The ISO is proposing position limits which will allow both the 15-minute market and the energy imbalance market to be implemented prior to convergence bidding returning on the interties.** **After considering stakeholder comments, Management modified the position limit proposal to not reinstate convergence bidding until 12 months after the new market structure is implemented. This will allow the ISO and stakeholders to review the market results under the new structure and EIM before reintroducing convergence bidding on the interties.**			

	Management Proposal: PIRP Design Changes			
	Forecasts & Scheduling	**Allow Economic Bid**	**No Monthly Netting of Imbalance Energy**	**No Grandfathering of Existing PIRP Resources**
CalWEA	Support Use of T-7.5 minute forecast for real-time dispatch is a significant improvement, but T-37.5 minute forecast for 15-minute market should be shortened when supported by WECC.	No Comment	Oppose Requests that monthly imbalance settlement netting schemes be kept in place for at least a year after all market changes are fully implemented.	Oppose PIRP should be grandfathered for all projects with existing power purchase agreements that were executed during PIRP's existence.
Iberdrola	Support Significantly improves the granularity of forecast data used to populate variable energy resources energy schedules.	Support	Support Scheduling coordinator for 570 MWs of wind in ISO. Proposal settles variable energy resources on a level that is comparable to all other generator types.	Conditional Certain variable energy resources may have operational characteristics that preclude their ability to mitigate imbalance risk under the new market structure. PIRP imbalance netting should be continued for these projects.
IEP	No Comment	No Comment	Conditional "Hold harmless" PIRP resources that have no reasonable means of cost recovery of additional costs due to elimination of the netting period associated with imbalance energy.	
LSA	Conditional Concerned that, while the proposal allows	No Comment	Oppose Monthly imbalance netting should apply to the small number of	

	Management Proposal: PIRP Design Changes			
	Forecasts & Scheduling	**Allow Economic Bid**	**No Monthly Netting of Imbalance Energy**	**No Grandfathering of Existing PIRP Resources**
	use of 5-minute forecast to reflect expected intra-hour ramps, the method for constructing 15-minute schedules, and measuring 5-minute imbalances from them, would undercut the benefits of the greater granularity.		contracts under which suppliers are responsible for imbalance energy risk.	
NRG	Conditional Concerns about using a simple average of the three 5-minute forecasts instead of using each individual 5-minute forecast as the basis for determining 5-minute instructed deviations from 15-minute schedules.	No Comment	Oppose Grandfathering monthly netting for current PIRP resources until the consistent accuracy of the ISO's forecasts can be proven, and the reduced exposure to uninstructed deviations can be verified.	
PG&E	Support Closer timelines for forecasting production are key improvements that will enhance market efficiency and reduce deviations.	No Comment	Support Scheduling coordinators of intermittent resources should be given the correct price signals to determine whether to modify their output.	Support Claims that elimination of PIRP netting will cause widespread disruption in the market or cause risk of abrogation are false.
SCE	Support	Support	Support	Support Do not believe that the contemplated changes to PIRP would trigger a right to renegotiate in the majority of their intermittent power purchase contracts.
SDG&E	Support	Support	Support	

	Management Proposal: PIRP Design Changes			
	Forecasts & Scheduling	**Allow Economic Bid**	**No Monthly Netting of Imbalance Energy**	**No Grandfathering of Existing PIRP Resources**
				Support Grandfathering to hedge against "widespread market disruption" associated with the proposed PIRP modifications are largely misplaced, and borne of theoretical rather than actual concerns.
Six Cities	Support	No Comment	Support	Support
Management Response	**The proposed real-time market changes will allow the ISO to effectively and efficiently integrate a large amount of renewable variable energy resources into the fleet. The proposed real-time market is structured around the characteristics of variable energy resources. Variable energy resources can now be scheduled more effectively through with more granularity and significantly shortened forecast lead times. Management's proposal includes the ability of variable energy resources to provide economic bids indicating their willingness to be curtailed in over-generation conditions. This provides significant benefits to the resources and the ISO's ability to maintain system reliability.** **Management proposes to establish a process to identify existing PIRP resources that have operational characteristics that require additional protective energy settlement measures under the proposed market design changes. This process will be used to identify if there are any impacted resources, so that mitigation measures can be developed that address the specific issues identified.**			